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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment (U 39 E)	Rulemaking 17-06-026 (filed June 29, 2017)

PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) AND CALIFORNIA COMMUNITY CHOICE ASSOCIATION WORKING GROUP ONE REPORT ON BROWN POWER, RPS AND RA TRUE-UP (ISSUES 1 THROUGH 7)

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Dated: May 31, 2019

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Pursuant to the Administrative Law Judge's (ALJ) Scoping Memo and Ruling, dated February 1, 2019 (Scoping Memo), in Phase 2 of the Power Charge Indifference Adjustment (PCIA) proceeding, Pacific Gas and Electric Company (PG&E) respectfully submits the Final Report of Working Group One, Issues 1-7 (Final Report) on behalf of itself and the California Community Choice Association (CalCCA).[1] The Final Report is attached hereto as Exhibit A.

In addition to providing the Final Report, PG&E and CalCCA provide procedural background concerning the Working Group's process to consider Issues 1-7 in Section I, and summarize how the Final Report addresses such issues in Section II.

I. PROCEDURAL BACKGROUND

A. Working Group Scope

On October 11, 2018 the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-10-019 modifying the PCIA methodology. D. 18-10-019 determined that a second phase of the proceeding would be opened in order to establish a "working group" process to enable parties to further develop proposals for consideration by the Commission. On

[1] Pursuant to Commission Rule of Practice and Procedure 1.8(d), counsel for PG&E confirms that counsel for CalCCA has authorized this filing on behalf of both parties.

February 1, 2019 the Commission issued the Scoping Memo directing parties to convene working groups to further develop PCIA-related proposals for consideration by the Commission.

The Scoping Memo designated PG&E and CalCCA as Co-Leads of Working Group One: Benchmark True-Up and Other Benchmarking Issues (Working Group One). The Commission directed Working Group One Co-Leads to address Issues 1-7, which concern methodologies to calculate and true-up PCIA market price benchmarks (MBPs).[2] The Co-Leads were ordered to file a Final Report on Issues 1-7 on May 31, 2019 to enable adopted recommendations to be implemented in the Investor Owned Utilities' respective November updates to their 2020 Energy Resource Recovery Account ("ERRA") Forecast filings.[3]

B. Working Group Responsibilities and Final Report Development

As Co-Leads of Working Group One, CalCCA and PG&E are responsible for certain procedural tasks, leading the Working Group meetings, and ensuring the final reports of Working Group One are filed and served at the Commission according to the schedule set forth in the Scoping Memo. PG&E and CalCCA are also responsible for producing two progress reports, attached hereto as Exhibit E and Exhibit F.

To further the development of the recommendations contained within Final Report, the Co-Leads individually met to develop straw proposals for consideration and feedback by the broader working group. The Co-Leads hosted three formal Working Group meetings concerning Issues 1-7. The initial meeting was held on March 1, 2019 and meeting materials and informal party comments are provided as part of the First Progress Report, attached as Exhibit F. The second formal meeting was held on March 26, 2019, and meeting materials and informal parties' comments are provided as part of the Second Progress Report, attached as Exhibit E. The final meeting was held on May 16, 2019.

At the final working group meeting, the Co-Leads presented an End-to-End Benchmark and True-up Proposal, which also identified certain limited areas of non-consensus between the

[2] Scoping Memo at p. 4.
[3] Scoping Memo at p. 6.

Co-Leads. Meeting materials are contained within Exhibit D. On May 20, 2019, the Co-Leads served parties to R. 17-06-026 with a Draft End-to-End Benchmark and True-up Proposal, which forms the basis of the Final Report for informal comments. On May 21, The Utility Reform Network (TURN) served parties to R. 17-06-026 with a proposal concerning the inclusion of bundled energy transactions within the MPB (TURN Proposal), which is attached as Exhibit C. The Final Report references Informal comments from parties on the End-to-End Benchmark and True-up Proposal as well as the TURN Proposal. Those comments are also attached as Exhibit B.

II. FINAL REPORT RESOLUTION OF ISSUES 1-7

As described above, Co-Leads' Final Report provides the Commission with an End-to-End Benchmark and True-up Proposal to address Issues 1-7. Below, the Co-Leads identify the questions posed in the scoping memo and provide reference to sections of the Final Report addressing those issues, including areas of non-consensus between Co-Leads. Section II of the Final Report summarizes non-consensus items among the Co-Leads and/or other working group members. Section III of the Final Report summarizes consideration of the TURN Proposal.

A. Issue 1: Annual True-Up

The Scoping Memo asked parties to consider "Which mechanism(s), procedural and/or methodological, should the Commission adopt to true-up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?" The Final Report addresses the true-up of the Brown Power component in Section I.C.2, the RA adder in Section I.D.3, and the RPS adder in Section I.E.3. Co-Leads present alternative proposals to address true-up of the RA adder and the RPS adder in Section I.D.3 and I.E.3, respectively.

B. Issue 2: Whether New Data and Transaction Reporting Requirements is Needed

The Scoping Memo asked parties to consider "Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?" Section I.F. addresses this issue.

C. Issue 3: Regulatory Proceedings to Address True-Up

The Scoping Memo asked parties to consider "Should the true up process be addressed as part of the annual Energy Resource Recovery Account [ERRA] proceedings? If not, where should the true up process be addressed?" Sections I.C.2 addresses this issue for energy, Section I.D.3 and I.E.3 addresses this issue for RECs and RPS, respectively.

D. Issue 4: Development of the RA and RPS Adder

The Scoping Memo asked parties to consider "Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark?" Section I.D.2 addresses this issue for the RA, and Section E 2 addresses this issue for the RPS adder. The Co-Leads disagree on the price and quantity applicable to "unsold" RA and RPS in the true-up process, as further described in Section I.D.

E. Issue 5: Modification of or Creation of New Date Reporting Requirements

The Scoping Memo asked parties to consider "Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?" The Final Report addresses this issue in Section I.F.

F. Issue 6: Unsold RA

The Scoping Memo asked parties to consider "How should the Commission clarify/define forecasting amounts of unsold RA?" The Final Report addresses this issue in Section I.D.2. Co-Lead disagreement on this issue is also described in Section I.D.

G. Issue 7: De Minimis Price for Unsold RA

The Scoping Memo asked parties to consider that "D.18-10-019 specified that "a zero or de minimis price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a de minimis price, and if so, what are these parameters?" The Final Report addresses this issue in Section I.D.2, and application of a diminish price is an area of disagreement between Co-Leads.

III. LIST OF EXHIBITS

Attached exhibits are identified in the table below.

Exhibit	Description
A	Final Report
B	Informal comments on the End-to-End Benchmark and True-up Proposal and TURN Proposal
C	TURN Proposal
D	May 16, 2019 Working Group Meeting Materials
E	Second Progress Report
F	First Progress Report

IV. CONCLUSION

The Co-Leads to the Phase 2, Working Group One appreciate the Commission's consideration of the Final Report and party comments on its near-final version. As a result of the working group process, the Co-Leads have significantly narrowed the issues requiring a

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Commission determination. We appreciate the Commission's consideration of the attached Final Report and party comments in issuing a decision on Phase 2 issues within Working Group One's remit.

Respectfully Submitted,

By: *{/s/ Maria V. Wilson}*
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Dated: May 31, 2019

EXHIBIT A

I. PCIA OIR Phase 2 Working Group 1 Co-Lead Proposal

This document was prepared by the Power Charge Indifference Adjustment (PCIA) Order Instituting Rulemaking (OIR) Phase 2, Working Group One to address the benchmarks used in developing the PCIA rate and the process to true-up the PCIA rate. This Section presents the proposal for calculating and truing up the PCIA rate as developed by Pacific Gas and Electric Company (PG&E) and the California Community Choice Association (CalCCA), the Co-Leads of this working group. This Section provides procedural background (Subsection A); an overview of the benchmark and true-up proposal (Subsection B); detailed descriptions for the forecast valuation and true up processes for the Brown Power Index, the Resource Adequacy (RA) Adder, and the Renewables Portfolio Standard (RPS) Adder (Subsections C, D, and E); and the data and reporting requirements for implementing the proposal (Subsection F). Open items of non-consensus are highlighted in sections II and III. Of note, this document does not explain the differences between how the PCIA is currently forecasted and the Co-Leads' proposed future state. Rather, it is a clean slate, end-to-end description of how the proposed benchmark and true-up calculation should work. A draft of this document was distributed on May 20th, 2019. Any substantive changes made since the draft was distributed to parties are *italicized*.

This proposal includes the use of new reporting templates for calculating the RA Adder and RPS Adder. These templates are supplemental to the Commission's and CAISO's current reporting requirements, which would be unaffected by Commission adoption of this proposal.

A. Procedural Background

On October 11, 2018 the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-10-019 modifying the PCIA methodology. D. 18-10-019 determined that a second phase of the proceeding would be opened in order to establish a "working group" process to enable parties to further develop proposals for consideration by the Commission. On February 1, 2019 the Commission issued a scoping memo in Rulemaking (R).17-06-026 directing the parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission (Phase 2 Scoping Memo).

The Phase 2 Scoping Memo designated PG&E and CalCCA as Co-Chairs of Working Group One: Benchmark True-Up and Other Benchmarking Issues (Working Group One). The

Commission anticipates resolving Working Group One issues "in time to be implemented in the Joint Utilities respective 2020 ERRA Forecast Updates in early November 2019" and the Phase 2 Scoping Memo established a procedural schedule to do so, with a proposed decision on brown power, renewable portfolio standard, and resource adequacy true-up issues issued by September 2019. The following section states the scoping memo issues the Co-Leads are directed to resolve.

1. Scoping Memo Issues 1-7

The subsection reference below each Scoping Memo issue indicates where in Section I of this report the issue is addressed.

1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
   See subsections C2, D3, E3
2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?
   See subsection F
3. Should the true up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true up process be addressed?
   See subsections C2, D3, E3
4. Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark?
   See subsections D, E
5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?
   See subsection F
6. How should the Commission clarify/define forecasting amounts of unsold RA?
   See subsection D2

7. D.18-10-019 specified that "a zero or de minimis price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a de minimis price, and if so, what are these parameters?

   See subsection D2

B. PCIA Forecast and True-up Overview

1. Forecasting the PCIA Indifference Amount

The California Investor Owned Utilities (IOUs) forecast a PCIA total portfolio indifference amount annually, which is used to set vintaged PCIA rates for the following year (year n). The forecasted total portfolio indifference amount is the forecasted total cost of the PCIA portfolio less the value of the PCIA portfolio attributes and is calculated on a vintaged basis.[1] The attributes valued in the total portfolio indifference amount calculation are energy, RA, and products that meet RPS compliance requirements.[2] The value of each of these attributes in the forecast depends on whether the attribute is retained by the IOU (Forecast Retained), Sold by the IOU (Actual Sold), forecast to be sold by the IOU (Forecast Sold), or forecast to remain unsold by the IOU (Forecast Unsold).[3] The value of each category is described in sections C, D, and E for each of energy, RA, and RPS.

2. True-up Using the Portfolio Allocation Balancing Account (PABA)

The total portfolio indifference amount calculation is based on forecasted costs and values. Actual costs and actual energy, RA, and RPS revenues, including imputed revenues for volumes of products retained by the IOU, are recorded to the Portfolio Allocation Balancing Account (PABA) in vintaged subaccounts. The value recorded to PABA depends on whether the attribute is retained by the IOU (Actual Retained), Sold by the IOU (Actual Sold), or is considered unsold

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[1] The total portfolio indifference amount is vintaged, or calculated for each year based on resources' contract execution date for contracts and construction start date for UOG, consistent with D.08-09-012, Finding of Fact 15.

[2] Excluding Tree Mortality PPAs and PPAs that satisfy the Green Tariff Shared Renewables Program requirements.

[3] Co-Leads disagree on the definition of unsold product for RA and RPS, as .

(Actual Unsold).[4] The actual revenues or imputed revenues are recorded to PABA as described in sections C, D, and E for each energy, RA, and RPS.

The year-end over- or under-collections in the PABA subaccounts for year n are included in the vintage PCIA rate calculation for year n+1 as part of each utility's ERRA Forecast proceeding.

3. Market Price Benchmarks (MPBs)

The following MPBs are used in the total portfolio indifference amount forecast and true-up:

- Energy MPB. The Energy MPB is called the Brown Power Index and is a separate value for each IOU in its respective ERRA Forecast Application.
- RA Adder. There are three types of RA Adders representing the market price of each type of RA compliance product: system, local, and flexible. There is a separate Local RA Adder for each IOU Transmission Access Charge (TAC) area based on transacted RA used to fulfill local RA requirements. There is a single Flexible RA Adder used by all three IOUs, calculated using transacted flexible RA not used for local purposes. There is a single System RA Adder used by all three IOUs, based on transacted RA not used for local or flex purposes. No megawatt is used to calculate more than one type of adder.
- RPS Adder. There is a single RPS Adder used by all three IOUs, based on index-plus PCC-1 RPS energy transactions.

CPUC Energy Division will calculate the Brown Power Index, the RA Adder and the RPS Adder annually for both the forecast and true-up. The Energy Division will conduct quarterly data requests (requiring information on an incremental basis each quarter) from all load serving entities (LSEs) on transactions of RA and RPS products to inform creation of the RA and RPS adders. The Brown Power Index will be calculated using Platts forward prices. In the future, Energy Division will have the discretion to conduct the data requests less frequent than quarterly. The MPBs are calculated as described below in sections C, D, and E for each energy, RA, and RPS.

[4] Co-Leads disagree on the definition of unsold product for RA and RPS, as described below.

C. Energy

1. Energy: Forecast Price and Quantity

Forecasted Energy Revenues will be used in each IOU's annual Energy Resource Recovery Account (ERRA) Forecast to set the total portfolio indifference amount for the following year. Forecasted energy revenues are the product of the Brown Power Index ($/MWh) and the forecasted energy generation (MWh) from resources eligible for recovery under PCIA methodology. For each vintage, forecasted energy revenues for each resource within the vintage will be credited at the Brown Power Index ($/MWh) against that resource's costs for purposes of calculating the total portfolio indifference amount in the annual ERRA Forecast Application for the following year ("year n").

The Brown Power Index is calculated using Platts[5] average published peak and off-peak market indices for a one-year strip of power for the coming calendar year for NP15 and SP15 published over the period October 1, through October 31 of the year prior to the forecast year.[6] This average is separately calculated for NP15 and SP15 and weighted using peak and off-peak weighting factors that reflect bundled customer load to derive a single Brown Power Index.[7] PG&E's benchmark is based on NP15 prices; Southern California Edison Company's (SCE) and San Diego Gas and Electric Company's (SDG&E) benchmarks are based on SP 15 prices.

2. Energy: True-up Revenue

The energy true-up amount for year n will be based on the realized net California Independent System Operator (CAISO) revenues ($) for all PCIA eligible resources and the realized revenues will include any revenues, if any, received through the CAISO's Capacity Procurement Mechanism (CPM). There is no Brown Power MPB used in the true-up. The realized revenues will be recorded to the vintaged resources' respective vintaged PABA subaccount and become an offset to actual costs recorded to the vintaged PABA subaccounts. The year-end over- or under-

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[5] D.06-07-030 adopted Megawatt Daily as the publication, which is no longer published. Platts publication was the successor publication.

[6] The methodology for calculating the Brown Power Index was established in D.06-07-030, Appendix 1, as superseded by D.11-12-018.

[7] D.11-12-018 modified the calculation to reflect bundled customer load.

collection in the vintaged PABA subaccounts for year n is included in the vintaged PCIA rate calculation for year n+1. The true up process will be addressed as part of the annual Energy Resource Recovery Account Forecast proceedings.

D. Resource Adequacy (RA) Adder

1. Resource Adequacy: Principles

The general principles for how RA value should be assessed in the PCIA are as follows:

1. RA product that is not offered for sale is valued at the applicable (forecast/final) benchmark.
2. RA product that is offered for sale and is sold is recorded to PABA at the transacted price.

The Co-Leads disagree on the valuation of unsold RA, and the definition of unsold RA product:

3a. PG&E Proposal: RA product that is offered for sale in a solicitation process consistent with IOU's approved Bundled Procurement Plan (BPP) but remains unsold will be valued at zero.

3b. CalCCA Proposal: Pending resolution of this issue by Working Group #3 or other Commission direction, "unsold" RA will be imputed a value equal to the IOUs' price floor (if there is one), or zero (if no floor) for amounts that are offered for sale *by the end of August preceding the compliance deadline for the relevant year*[8], but are not sold. Otherwise "unsold" amounts are treated as retained and valued at the MPB.

Co-Lead positions on the true-up of unsold RA are further described in Section II.B.

2. Resource Adequacy: Forecast Price and Quantity

RA value will be forecasted using the prices and quantities listed in Table 1a or 1b for the following categories of RA within the PCIA eligible portfolio: Forecast Retained RA, Actual Sold RA, Forecast Sold RA, and Forecast Unsold RA. As noted in the discussion of the

[8] CalCCA's proposal has been updated (emphasis added) since the final Working Group session and the distribution of the draft proposal. Parties' comments do not reflect this updated proposal.

principles for RA valuation, the Co-Leads disagree about the quantification and valuation of unsold RA. The tables below demonstrate the differences between the proposals. PG&E's and CalCCA's proposals follow.

Table 1a: PG&E's Proposal for Forecast of Resource Adequacy Value for PCIA Calculation

	Forecast Retained	Actual Sold	Forecast Sold	Forecast Unsold
Price ($/kW-year)	June: Forecast RA Adder published in November of previous year November: Forecast RA Adder as calculated by Energy Division	Actual transacted price for product transacted by ~45 days prior to ERRA Forecast filing date	Applicable RA Adder	$0[3]
Quantity (MW)	June: IOU forecasted RA allocations plus amount retained for IOU use November: Final RA allocations, plus amount retained for IOU use[1]	Actual transacted volume of RA executed up to ~45 days prior to ERRA Forecast filing date	Forecasted sold volume	Forecasted unsold volume[2]

1. The amount of RA retained for IOU use is the amount of RA not offered for sale or forecasted to be offered for sale. The Forecast Retained RA includes but is not limited to any compliance reserves.

2. The IOU can forecast any volume of unsold RA. If the forecasted volume is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review. The calculation of the amount corresponding to the change in departing load is the product of the year-over-year difference in IOU load share and the system RA requirement for each month. Volumes outside of range may be subject to reasonableness review in the ERRA Forecast proceeding. 3. Forecast Unsold RA is valued at zero regardless of whether an IOU uses floor prices in its solicitations. An IOU may use a price floor consistent with its BPP and will consult on the use of price floors with an IE and its PRG.

Table 1b: CalCCA's Proposal for Forecast of Resource Adequacy Value for PCIA Calculation				
	Forecast Retained	Actual Sold	Forecast Sold	Forecast Unsold
Price ($/kW-year)	<u>June</u>: Forecast RA Adder published in November of previous year <u>November</u>: Forecast RA Adder as calculated by Energy Division	Actual transacted price for product transacted by ~45 days prior to ERRA Forecast filing date	Applicable RA Adder	$0[1]

Quantity (MW)	June: IOU forecasted RA allocations plus amount retained for IOU use to serve bundled load November: Final RA allocations, plus amount retained for IOU use to serve bundled load[1]	Actual transacted volume of RA executed up to ~45 days prior to ERRA Forecast filing date	Forecasted sold volume	Forecasted unsold volume[2]

Notes:

1. Amount retained for IOU use includes but is not limited to any compliance reserves. The definition of "unsold" remains unresolved and is under consideration in Working Group 3.
2. The IOU can forecast any volume of unsold RA. If the forecasted volume is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review. The calculation of the amount corresponding to the change in departing load is the product of the year-over-year difference in IOU load share and the system RA requirement for each month. Volumes outside of range may be subject to reasonableness review in the ERRA Forecast proceeding.

a) Calculating the Forecast RA Market Price Benchmark

The three types of RA Adders are described in Section I B.3. For each type, Energy Division will calculate and publish the Forecast RA Adders for year n at the beginning of November in year n-1. For system and flexible RA, the Forecast RA Adder is calculated using IOU, CCA, and ESPs' RA-only market-based transactions executed in Q4 of n-2 and Q1-Q3 of n-1 for delivery in year n. The annual RA Adder ($/kW-year) is the sum of the monthly weighted average of the relevant transactions (i.e., for system, all non-local, non-flexible transactions executed within the execution window for delivery in year n).

LSEs currently have a 3-year forward local RA requirement starting for compliance year 2020. Therefore, the execution window for calculating the Forecast Local RA Adder will vary as the three year forward requirement is implemented. For 2020, the forecast local RA Adder will be calculated for each IOU TAC area using IOU, CCA, and ESP local RA-only market-based transactions executed in Q4 of year n-2 and Q1-Q3 of year n-1 for 2020 delivery. For delivery in 2021 and beyond, the calculation will use transactions executed in years n-1 and n-2 for delivery in n (e.g., 2021). If, however, a central buyer is adopted by the Commission for local RA procurement, as is currently being considered in R.17-09-020, the methodology for calculating the local RA Adder should be revisited.

3. RA: True-up Price and Quantity

Actual RA value will be calculated using the prices and quantities listed in Tables 2a and 2b for the following categories of RA within the PCIA eligible portfolio: Actual Retained RA, Actual Sold RA, and Actual Unsold RA. The true up process will be addressed as part of the annual Energy Resource Recovery Account Forecast proceedings.

As noted in the discussion of the principles for RA valuation, the Co-Leads disagree about the quantification and valuation of unsold RA. The tables below demonstrate the differences between the proposals. PG&E's and CalCCA's proposals follow.

Table 2a: PG&E's Proposal for Trued Up Resource Adequacy Value for PCIA Calculation			
	Actual Retained	Actual Sold	Actual Unsold
Price	Final RA Adder as calculated by Energy Division	Actual transacted price	$0
Quantity	RA used for compliance from the PCIA portfolio plus amount retained for IOU use [1]	Actual transacted volume	Quantity offered for sale but not sold or used by IOU[2]
1. The final amount retained for IOU use is any RA that was not offered for sale, consistent with the IOU's BPP. The total volume of Retained RA may be lower than the total amount of an IOU's RA compliance obligation because the IOU may use non-PCIA-eligible resources to meet its RA requirements (e.g., transactions of less than one year, CAM resources).			

2. The IOU will identify the quantity offered for sale to the IE and PRG and will document the quantity offered in its QCR. Any volume offered for sale and not sold is Actual Unsold RA.

CalCCA's proposal below is intended as an interim measure pending resolution of these issues in Working Group 3.

Table 2b: CalCCA's Proposal for Trued Up Resource Adequacy Value for PCIA Calculation			
	Actual Retained	Actual Sold	Actual Unsold
Price	Final RA Adder as calculated by Energy Division	Actual transacted price	Price floor used in the solicitation, if any; if no price floor then zero[1]
Quantity	RA used for compliance from the PCIA portfolio plus amount retained for IOU use to serve bundled load[1]	Actual transacted volume	Quantity offered for sale *by the end of August preceding the compliance deadline for the relevant year*
1. Amount retained for IOU use includes but is not limited to any compliance reserves. The definition of "unsold" remains unresolved and is under consideration in Working Group 3.			

a) Calculating the Final RA Market Price Benchmark

The three types of RA Adders are described in Section I B.3. For each type, Energy Division will calculate and publish the Final RA adders for year n at the beginning of November of year n. The methodology for calculating the Final RA adders for system and flexible RA is the same as for calculating the Forecast RA Adders except that the transactions from Q4 of year n-2 will be excluded, and the data will be supplemented with transactions executed in Q4 of year n-1 for delivery in year n and transactions executed in Q1-Q3 of year n for delivery in year n. *Inputs into the Final RA Adder for local RA will be supplemented with transactions executed in Q1-Q3 of year n for delivery in year n. Calculation of the Local RA Adder may be revisited if a central buyer structure is adopted.*

Table 3: Forecast and Final Adders[9]			
	System and Flex RA Adders	Local RA Adder	RPS Adder
<u>Transaction Types</u> Used to Calculate Adders	Sum of monthly weighted averages for relevant IOU, CCA, and ESP market-based RA-only transactions	Same as System/Flex RA	Volume-weighted average of all IOU, CCA and ESP index-plus market-based PCC1 REC transactions
<u>Forecast Adder</u> Dataset	Transactions executed in Q4 of n-2 and Q1-3 of n-1 for delivery in year n.	**2020**: Transactions executed in Q4 n-2 and Q1-3 of n-1 for delivery in year n. **2021 and Beyond:** Transactions executed in n-2 for delivery in year n.	Same as System/Flex RA
<u>Final Adder</u> Dataset	Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n.	**2020**: Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n. **2021 and Beyond:** Transactions executed in n-2, n-1, and Q1-3 of n for delivery in year n.	Same as System/Flex RA

The year-end over- or under-collection in the vintaged PABA subaccounts related to Actual Retained RA, Actual Sold RA, and Actual Unsold RA for year n is included in the vintaged PCIA rate calculation for year n+1, as part of each utility's ERRA Forecast proceeding.

[9] Working Group 1 Questions 1-7 Workshop #3, slide 26

4. Resource Adequacy: Allocation of Revenue and Imputed Market Value

RA revenues or imputed market values will be allocated by vintage according to the methodologies and order described below:

1. For revenue from Actual Sold RA that is resource specific, revenue will be allocated in the forecast to the corresponding resource specific vintage and recorded in the true-up to corresponding resource specific PABA vintage subaccount.
2. For revenue from Forecast Sold RA and Actual Sold RA that is not resource specific, revenue will be allocated pro rata (defined below) in the forecast and recorded in the true-up to the PABA vintage subaccounts on a Pro Rata (defined below) basis.
3. For Forecast Retained RA and Actual Retained RA imputed market value, the imputed market value will be allocated pro rata in the forecast and recorded in the true-up to the PABA vintage subaccounts on a pro rata basis.

The Co-Leads disagree on the allocation of unsold RA.

4a. PG&E Position: For RA that is offered for sale consistent with the IOU's BPP and remains unsold, no revenue will be allocated in the forecast nor recorded in the true-up.

4b. CalCCA Position: CalCCA agrees with PG&E regarding the allocation for forecast purposes. The volume of Unsold RA will be determined in Working Group 3. *Until established in Working Group 3, the volume of unsold RA will be the volume of RA offered by the IOU by the end of August preceding the compliance deadline of the relevant year.* In the true-up, the price assigned to any Unsold RA should be a de minimis price equal to the IOUs' floor price, and imputed market value should be allocated pro rata.

The pro rata allocation for RA will be based on the quantity of RA MW for each type of RA (system, flexible, and local) in each vintage. For example, if the 2009 vintage has 10 percent of the total system RA MWs in the PCIA portfolio, 10% of the revenues will be allocated to the 2009 vintage in the forecast and recorded to the 2009 PABA vintage subaccount in the true-up.

The pro rata revenue allocation is meant to maintain indifference among all customers by allocating RA sales revenue and imputed market value to the vintaged portfolios in a way that most fairly distributes the revenues and imputed market value to the responsible group of customers. Allocating revenues first to the earliest or latest vintages would benefit either earlier or later departing customers, respectively, compared to a pro rata allocation.

E. Renewables Portfolio Standard (RPS) Adder

1. RPS: Principles

The general principles for how the RPS value should be assessed in the PCIA are as follows:

1. RPS product that is not offered for sale or is used for RPS compliance is valued at the applicable (forecast/final adder).
2. RPS product that is offered for sale and is sold is recorded to PABA at the transacted price.

The Co-Leads disagree on the valuation of unsold RPS:

3a. PG&E Proposal: No revenue is recorded to PABA for RPS product that is offered for sale consistent with the IOU's RPS plan and remains unsold. If previously unsold RPS is sold in a future year, it is valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it is valued at the applicable future year's RPS Adder.

3b. CalCCA Proposal: The volume of RPS retained by IOUs is under consideration in Working Group 3. Unsold RPS should be valued at the benchmark.

Co-Lead positions on the true-up of unsold RPS are further described in Section II.C. These principles apply to RPS generated commencing January 1, 2019 and going forward. Existing RECs that were generated in 2018 or before have already been bought and paid for by bundled customer at previous years' RPS Adders.

2. RPS Adders: Forecast Price and Quantity

RPS value will be forecasted using the prices and quantities listed in Table 3 for the following categories of RPS within the PCIA eligible portfolio: Forecast Retained RPS, Actual Sold RPS, and Forecast Sold RPS.

Table 4: Forecast of RPS Value for PCIA Calculation			
	Forecast Retained	Actual Sold	Forecast Sold
Price ($/MWh)	June: Forecast RPS Adder published in November of previous year November: Forecast RPS Adder	Actual transacted price for any transactions executed up to ~45 days prior to ERRA Forecast filing date	Applicable RPS Adder
Quantity (MWh or GWh)	Forecasted IOU RPS Compliance Need	Actual transacted volume of RECs transacted by ~45 days prior to ERRA Forecast filing date, plus forecasted additional sales (if any)	Forecasted sold volume

a) Calculating the Forecast RPS Adder

Energy Division will calculate the RPS Adder for year n at the beginning of November preceding year n. There is a single Forecast RPS Adder used by all three IOUs. The Forecast RPS Adder is the volume-weighted average of all IOU, CCA, and ESP's market transactions (i.e., "PCC 1 index-plus" deals) executed in Q4 of n-2 and Q1-Q3 of n-1 for delivery in year n. For example, the Forecast RPS Adder for the 2020 compliance year will be based on sales from Q4 2018 through Q3 2019 for delivery in 2020.

3. True-up Price and Quantity

Actual RPS value will be calculated using the prices and quantities listed in Tables 4a and 4b for the following categories of RPS within the PCIA eligible portfolio – Actual Retained RPS, Actual Sold RPS, and Actual Unsold RPS. The true up process will be addressed as part of the annual Energy Resource Recovery Account Forecast proceedings.

As noted in the discussion of the principles for RPS valuation, the Co-Leads differ on the valuation of unsold RPS product. The tables below detail the differences between the positions. PG&E and CalCCA's proposals follow.

PG&E Proposal:

Table 5a: PG&E Proposal on Trued Up RPS Value for PCIA Calculation			
	Retained	Actual Sold	Unsold
Price ($/MWh)	Final RPS Adder	Actual transacted price	No credit
Quantity (MWh or GWh)	Volume used for IOU compliance from the PCIA-eligible portfolio[1]	Actual transacted volume	Actual unsold volume[2,3]

Notes:

1. Retained RPS includes the volume of RPS from the PCIA portfolio that the IOU does not offer for sale, consistent with its RPS Plan. The total retained volume may be higher or lower than the total amount of an IOU's RPS obligation due to the IOUs compliance strategy over a multi-year compliance window or because the IOU may use non-PCIA-eligible resources to meet its requirement (PCC 3 product, tree mortality).
2. Actual volume of unsold includes volumes offered for sale that remain unsold plus any deviations from forecasted RPS generation (i.e., if renewable resource produced more or less than forecasted in the year ahead timeframe, that value would be added or subtracted to the unsold volume in the true-up).
3. Does not include unsold volumes that were not offered for sale due to CPUC sales restrictions (PURPA).

Table 5b: CalCCA Proposal on Trued Up RPS Value for PCIA Calculation		
	Compliance/Otherwise Retained (including "unsold" amounts)	Actual Sold
Price ($/MWh)	Final RPS Adder	Actual transacted price
Quantity (MWh or GWh)	Volume generated from the PCIA-eligible portfolio minus generation sold from the PCIA-eligible portfolio.	Actual transacted volume

a) Calculating the Final RPS Adder

Energy Division will calculate and publish the Final RPS Adder for year n at the beginning of November of year n. The methodology for calculating the Final RPS Adder is the same as for calculating the Forecast RPS Adder except that the transactions from Q4 of year n-2 will be excluded and will be supplemented with transactions executed in Q4 of year n-1 for delivery in year n and transactions in Q1-Q3 of year n for delivery in year n.

Table 6: Forecast and Final Adders[10]

	System and Flex RA Adders	Local RA Adder	RPS Adder
<u>Transaction Types</u> Used to Calculate Adders	Sum of monthly weighted averages for relevant IOU, CCA, and ESP market-based RA-only transactions	Same as System/Flex RA	Volume-weighted average of all IOU, CCA and ESP index-plus market-based PCC1 REC transactions
<u>Forecast Adder</u> Dataset	Transactions executed in Q4 of n-2 and Q1-3 of n-1 for delivery in year n.	**2020**: Transactions executed in Q4 n-2 and Q1-3 of n-1 for delivery in year n. **2021 and Beyond:** Transactions executed in n-2 for delivery in year n.	Same as System/Flex RA
<u>Final Adder</u> Dataset	Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n.	**2020**: Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n. **2021 and Beyond:** Transactions executed in n-2, n-1, and Q1-3 of n for delivery in year n.	Same as System/Flex RA

[10] Working Group 1 Questions 1-7 Workshop #3, slide 26

The year-end over- or under-collection in the vintaged PABA subaccounts related to retained, sold, and unsold RPS products for year n is included in the vintaged PCIA rate calculation for year n+1, as part of each utility's ERRA Forecast proceeding.

4. RPS: Allocation of Revenue and Imputed Market Value

RPS revenues or imputed market value will be allocated by vintage according to the methodologies and order described below:

1. For revenue from Actual Sold RPS that is resource specific, revenue will be allocated in the forecast to the corresponding resource specific vintage and recorded in the true-up to corresponding resource specific PABA vintage subaccount.
2. For revenue from Forecast Sold RPS and Actual Sold RPS that is not resource specific, revenue will be allocated pro rata in the forecast pro rata and recorded in the true-up to the PABA vintage subaccounts on a Pro Rata basis.
3. For Forecast Retained RPS and Actual Retained RPS imputed market value, the imputed revenue will be allocated pro rata in the forecast and recorded in the true-up to the PABA vintage subaccounts on a pro rata basis.

The Co-Leads differ on the valuation of unsold RPS product.

4a. PG&E proposal: For Unsold RPS offered for sale consistent with the IOU's RPS Plan and remains unsold, no imputed market value will be recorded in the true-up.

4b. CalCCA proposal: All retained RPS products will be valued at the RPS benchmark, including "unsold" volumes. Imputed market value will be recorded in the true-up pursuant to (3) above.

The pro rata revenue allocation methodology and the rationale for using this approach is described previously.

F. Data Request Templates

The Co-Leads have met with the Energy Division several times over the course of the working group process to develop robust data request templates to collect the information necessary to calculate the RA and RPS adders. The clean slate templates displayed below were developed for the purpose of calculating the RA and RPS Adders for the PCIA calculation. They are supplemental to existing templates.

RA Data Template:

Data Field:	**Data Field Description:**
Reporting LSE's Contract ID	Insert the LSE's unique contract identifier
Month	From the drop-down, select the delivery month for which the price quoted is applicable; Please insert an additional row for each month regardless of whether capacity price or capacity MW amount changes between months
Year	From the drop-down, select the year of delivery
CAISO Resource ID	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list
Resource Name	Name of resource; This field will automatically populate if you select a CAISO Resource ID
Buyer	From the drop-down, select the contract buyer identified on the RA confirmation
Seller	From the drop-down, select the contract seller identified on the RA confirmation
System Capacity Under Contract (MW)	The amount of system MW(s) under contract for the associated month and year of the contract.

Flexible Capacity Under Contract (MW)	The amount of flexible MW(s) under contract for the associated month and year of the contract; System and flexible capacity are a bundled product; Do not list a MW amount greater than the system MW amount
Price ($/kW-month)	List the price in $/kW-month format for each month and year of a contract even if the price is same for all months of the year; For example, if a contract covers a 3 year period, you will input 36 lines for the contract
Contract Execution Date	List the date the contract has been executed - mm/dd/yyyy
Type of Generation	Select whether the resource is new, existing, or imported generation; A repower will be considered new generation for this application
Local Area	For "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, provide the expected Local Area; This field will automatically populate if you select a CAISO Resource ID on the NQC list; Provide as "CAISO System" if the contract is for a local CAISO Resource ID transacted for a system RA product
Zone	For "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, provide the expected Zone; This field will automatically populate if you select a CAISO Resource ID on the NQC list
RA Adder	Field is formula based for Commission purposes only
Transaction ID	Field is formula based for Commission purposes only

RPS Data Template:

Data Field:	**Data Field Description:**

Contract ID Between Parties	Insert the parties' unique contract identifier
Purchase or Sale by Reporting LSE	From the drop-down, select whether the transaction is a purchase or sale by reporting LSE
Year	From the drop-down, select the year of delivery
CAISO Resource ID	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list
Resource Name	Name of resource; This field will automatically populate if you select a CAISO Resource ID
Buyer	From the drop-down, select contract buyer identified on the RPS confirmation
Seller	From the drop-down, select contract seller identified on the RPS confirmation
PCC Classification	The expected PCC classification under the contract for the associated year of delivery
Volumes (MWh)	List the expected volumes in megawatt hours under contract for the associated year of delivery
Price ($/MWh)	List the price in $/MWh format under contract for the associated year of delivery; For REC + Energy (Index), provide the REC-only premium price
Contract Execution Date	List the date the contract has been executed - mm/dd/yyyy
Transaction ID	Field is formula based for Commission purposes only

II. Non-consensus Items

There were several areas of difference between the Co-Leads and one area in which the Co-Leads did not reach consensus with stakeholders. For each of these issues, the alternative proposals are described below and arguments for or against are attached in comments.

A. Capacity Procurement Mechanism[11]

The Co-Leads previously disagreed on whether to include CPM in the RA Adder calculation. Co-Leads have now agreed to exclude CPM from the RA Adder calculation and record CPM revenues in the PABA.

B. True-Up of Unsold RA

The Co-Leads do not agree on the quantity and valuation of unsold RA product. The proposals are described briefly below, and addressed in more detail in the attached comments (Exhibit B).

PG&E Position:

- Unsold RA Quantity: Each IOU will identify the quantity of RA offered for sale to an Independent Evaluator (IE) and its PRG in advance of when bids are due and will document the quantity offered in the Quarterly Compliance Report (QCR). The RA offered for sale will be consistent with the BPP, which is reviewed and approved by the CPUC with opportunity for stakeholder participation. Any of the offered quantity that is not sold is Actual Unsold RA.
- Unsold RA Value: RA that is offered for sale but is not sold is not assigned credit in PABA for the true-up.

CalCCA Position:

- Unsold RA Quantity: *Offered for sale by the end of August preceding the compliance deadline* for the relevant year, but not sold.

[11] CalCCA's position has been updated since the final Working Group session and the distribution of the draft proposal. Parties' comments do not reflect this updated proposal. The following parties submitted comments on the inclusion of the CPM: TURN, City of San Diego, POC, CLECA, Joint IOUs, and CalCCA. These comments are attached to this report (Exhibit B).

- Unsold RA Value: Pending resolution of this issue by Working Group #3 or other Commission direction, "unsold" RA will be imputed a value equal to the IOUs' price floor (if there is one), or zero (if no floor)

The following parties also submitted comments on the true-up of Unsold RA: TURN, City of San Diego, POC, AReM/DACC, CLECA, Joint IOUs, and CalCCA. These comments are attached to this report (Exhibit B).

C. True-up of Unsold RPS

The Co-Leads do not agree on the valuation of unsold RPS product. The proposals are described briefly below, and addressed in the attached comments (Exhibit B).

PG&E Position:

- Unsold RPS Quantity: Each IOU will identify the RPS offered for sale to an IE and its PRG in advance of when bids are due and will document the quantity offered in the Advice Letter seeking approval of transactions resulting from the solicitation. The RPS offered for sale will be consistent with the RPS Plan, which is reviewed and approved by the CPUC with opportunity for stakeholder participation. Any of the offered quantity that is not sold is Actual Unsold RPS.
- Unsold RPS Value: RPS that is offered for sale consistent with the IOU's RPS Plan but remains unsold will not be assigned credit in PABA until the value of the RPS product, if any, is known. If previously unsold RPS is sold in a future year, it is valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it is valued at the applicable future year's RPS Adder. If Unsold RPS is never used, it is not assigned credit.

CalCCA Position:

- Unsold RPS Quantity: CalCCA proposes only two categories of RPS, retained and sold, so determining when RPS attributes are "unsold" is unnecessary.
- Unsold RPS Value: Unsold RPS product should be valued at the benchmark

The following parties also submitted comments on the true-up of Unsold RPS product: TURN, City of San Diego, POC, AReM/DACC, CLECA, Joint IOUs, CalCCA. These comments are attached to this report (Exhibit B).

D. Confidentiality

Several parties expressed concern over sharing confidential, commercially sensitive data with the Commission for the purposes of calculating the market price benchmarks. Parties noted that the Commission does not have jurisdiction over ESPs' rates and therefore the commercial data should only be provided under certain conditions. Suggestions included restriction of data access to the individuals within Energy Division tasked with calculating the benchmarks, application of rules governing market participants' access to confidential data, and destruction of data once the benchmarks have been calculated. These issues are described in more detail in the attached comments (Exhibit F, E, and B).

The Co-Leads assert that ALJ Atamturk's ruling on March 20, 2019 confirms that all data provided by LSEs is protected under D.06-06-066 and that destruction of commercial data would prevent audits of past adder calculations.

III. Alternatives Considered

A. Including Long-term Fixed Price Bundled PPAs in the RPS Adder Calculation

Early in the working group process, TURN raised the issue of integrating long-term fixed-price PPAs into the RPS Adder. TURN provided a proposal for including these contracts at the March 26, 2019 all party workshop. This proposal is attached to this report (Exhibit E). Several parties (CLECA, CUE, Office of Public Advocates, and Shell) supported either inclusion of long-term fixed-price PPAs or additional exploration. AREM/DACC highlighted some challenges to implementing TURN's proposal. These comments are attached to this report (Exhibit F and E).

The Co-Leads considered the proposal, but ultimately did not revise their proposal from using solely PCC1 index-plus transactions in calculating the RPS Adder. The Co-Leads provided a response in the May 16, 2019 all party workshop. This response is attached to this report (Exhibit D, slides 50-51).

On May 21, 2019, TURN circulated an updated proposal regarding incorporating fixed-price bundled renewable energy transactions into the Market Price Benchmark (MPB) analysis (Exhibit C). TURN states that "TURN is willing to accept the [Brown Power]+REC [what Co-Leads call index-plus] price approach subject to the requirement that all LSEs also be required to provide the Energy Division (ED) with information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past 3 years (n-3, n-2 and n-1) for delivery in the following three years (n,n+1, n+2)." TURN further asserts that "Data for each fixed-price bundled transaction should include price, contract duration, delivery node, hourly delivery profile and Resource Adequacy value." Finally, TURN calls for "an explicit sunset date for using the BP+REC pricing model at which time one or more models for estimating the market prices of RPS-eligible energy contracts could be considered (including re-adopting the BP+REC model for some portion of RPS-eligible energy)." TURN does not propose a particular sunset date.

The Co-Leads appreciate TURN's consideration of the challenges inherent in incorporating fixed-price bundled renewable energy transactions into the MPB. As detailed at the working group meetings and in the associated materials, after extensive investigation the Co-Leads were unable to arrive at an acceptable methodology for incorporating long-term fixed-price pricing into the RPS Adder that was consistent with the letter and spirit of D.18-10-019. In light of that experience, we agree with TURN that the appropriate approach is to go forward with using only index-plus transactions, while Commission Staff collect data on such transactions. We will work with Commission staff on data request templates.

The Co-Leads appreciate TURNs concerns about a possible market migration away from index-plus transactions towards long-term fixed-price transactions. However, any Commission-imposed sunset date would be arbitrary, and would not have been vetted in the working group process. Consistent with the "possible re-opener" slide from our final presentation, the Co-Leads recommend that the Commission not impose a sunset date at this time. Rather, the Co-Leads recommend that Energy Division monitor the state of the market to determine if/when it is appropriate to revisit the RA Adder in light of market changes. Simultaneously, parties may monitor the state of the market, and bring a petition for modification if/when it is appropriate to revisit the RPS Adder calculation in light of market changes.

UCAN submitted comments on the updated TURN proposal. These comments are attached to this report (Exhibit B).

EXHIBIT B

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON WORKING GROUP 1'S BENCHMARK PROPOSAL

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DATED: May 29, 2019

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OF THE STATE OF CALIFORNIA

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INFORMAL COMMENTS OF PROTECT OUR COMMUNITIES FOUNDATION ON WORKING GROUP 1'S BENCHMARK PROPOSAL

I. Introduction

On May 16, 2019, the co-chairs of Working Group 1 convened a meeting at which they presented the results of their discussions and deliberations regarding Scoping Memo Issues 1-7. The Protect Our Communities Foundation ("POC") attended the Working Group's May 16, 2019, March 26, 2019, and March 1, 2019 meetings. POC provides the following informal comments pursuant to the schedule set by the co-chairs.

POC thanks the co-chairs and agrees with their plan to formally file all the informal comments provided to the working group with the Commission as an attachment to the Working Group's final report.[1]

II. Resource Adequacy ("RA") Adder

A. Capacity Procurement Mechanism ("CPM") costs and revenues should be included in the RA Adder.

The RA Adder should include any CPM costs and revenues because they represent a load serving entity's actual procurement cost. California Community Choice Association

[1] POC requests that all the PCIA Working Group co-chairs in this proceeding to attach the slides presented and the parties' informal comments to their final filed Working Group report.

("CalCCA") proposes that the RA Adder should include CPM costs.[2] Pacific Gas and Electric Co. ("PG&E") opposes including CPM costs in the RA Adder, as CPM costs are not market-based, and actual CPM revenues are credited to the Portfolio Allocation Balancing Account.[3]

Nothing in the Commission's decision regarding PCIA design requires the exclusion of actual costs from the RA Adder. D.19-09-019 provides that the RA Adder "shall be calculated using reported purchase and sales prices of [investor-owned utility ("IOU"), Community Choice Aggregator ("CCA"), and Electric Service Provider ("ESP")] transactions."[4] PG&E and the California Large Energy Consumers Association ("CLECA") are wrong when they argue that D.19-09-019 allows only market-based costs and revenues in the RA Adder.[5] Nothing in D.19-09-019 requires that the reported purchase and sale prices be market-based prices. Thus, CalCCA's proposal to include CPM costs and revenues in the RA Adder should be adopted because CPM costs represent a load serving entity's actual procurement cost.

B. The Commission's interim decisions regarding unsold resources should be revisited when the Commission acts on Working Group 3's portfolio optimization recommendations.

The most important issues that the Commission directed the parties to resolve in Phase 2 of this proceeding involve the efficient allocation of excess resources from the investor-owned utilities to other load serving entities. This issue is slated for in-depth consideration in Working

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[2] May 16 Presentation, at p. 43.

[3] PCIA Phase 2: Working Group One, Benchmark True-Up and Other Benchmarking Issues, Working Group Meeting #3 on Scoping Memo Issues 1-7 Presentation, at p. 43 (May 16, 2019) ("May 16 Presentation").

[4] D.19-09-019, Decision Modifying the Power Charge Indifference Adjustment Methodology, at p. 73 (October 19, 2018).

[5] Informal Comments of the California Large Energy Consumers Association on Working Group One Workshop #2 Held March 26, 2019, at pp. 2-4 (April 2, 2019) ("CLECA Comments").

Group 3, which only recently began its work.[6] Unfortunately, the Commission is faced with the need to make an interim decision today that implicates the outcome of Working Group 3's efforts: how to account for unsold RA and RPS resources. Whatever interim outcome the Commission selects when making its decision regarding this issue now, it should require that the quantity and price of unsold resources used here are revisited after the Commission acts on Working Group 3's portfolio optimization recommendations. The remainder of this section addresses the quantity and value of unsold RA.

1. In this proceeding the Commission should establish the quantity of Unsold RA in the true-up, and establish shareholder responsibility requirements for IOUs that unreasonably withhold RA from competing load serving entities.

The co-chairs did not agree on the quantity or value of unsold RA in the true-up. Regarding quantity, CalCCA proposes that any unsold RA must be offered at the earliest annual solicitation, while PG&E does not support this requirement. PG&E suggests that its Advice Letter 5473-E, on which the Commission issued Draft Resolution E-4998, appropriately modifies its Bundled Procurement Plan ("BPP") to specify the quantity of RA it offers for sale.

PG&E's Advice Letter is a blatant attempt to bypass the deliberative process afforded to this Working Group and the Commission's formal processes. PG&E's Advice Letter 5473-E is premature and should be rejected. Instead, the Commission should issue a decision regarding these issues here in the PCIA docket, and then consider changes to PG&E's BPP that comply with the Working Group 1 decision. Instead of endorsing PG&E's proposal to bypass the work and input of the parties in this Working Group, the Commission should fully consider the options

[6] *See* Phase 2 Scoping Memo and Ruling of Assigned Commissioner, at p. 5 (February 1, 2019).

presented here, adopt CalCCA's definition and price of unsold RA, and adopt POC's shareholder responsibility proposals.

CalCCA raises serious concerns about PG&E's actions and about PG&E's position as the owner of a large quantity of RA resources. For example, CalCCA's *ex parte* notice describes PG&E's unreasonable hording of RA for the 2019 reliability year.[7] Peninsula Clean Energy was seeking to purchase local RA for the 2019 reliability year. It responded to all of PG&E's requests for offers and made other efforts to procure capacity, but was unable to procure enough local RA to meet its need.[8] The needed capacity was subsequently offered by PG&E to the market *after* the compliance deadline.[9] This example shows that IOUs are unreasonably withholding RA from competing load serving entities.

This example illustrates precisely why CalCCA's proposal to require unsold RA to be offered at the *earliest* annual solicitation is necessary. Without the requirement that the offer be made early enough to allow a buyer to purchase RA before its compliance obligation is due, PG&E's tardy offer to sell is of no use to the buyer. Yet under PG&E's proposal unbundled ratepayers would still pay, through the PCIA, for unsold power that was unreasonably withheld from their load serving entity. Thus, the Commission should adopt CalCCA's proposal to ensure that any RA counted as unsold was offered at time when it was of use to load serving entities.

POC proposes that the Commission establish shareholder responsibility mechanisms to allocate costs to shareholders when IOUs unreasonably withhold RA from competing load serving entities. First, the cost of any RA resource that is not offered for sale in advance of the

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[7] Notice of Ex Parte Meeting of the California Community Choice Assn., at p. 2 (May 13, 2019).
[8] Notice of Ex Parte Meeting of the California Community Choice Assn., at p. 2 (May 13, 2019).
[9] Notice of Ex Parte Meeting of the California Community Choice Assn., at p. 2 (May 13, 2019).

compliance deadline, and is not used to serve load, should be allocated to shareholders instead of bundled or unbundled customers. Without a framework that incorporates shareholder responsibility, the IOUs will lack sufficient incentives to offer their resources for sale with reasonable terms and in a reasonable time frame.

Second, POC proposes that the Commission allocate costs to IOU shareholders when an IOU's withholding of RA resources results in penalties to a competing load serving entity. For example, if the RA needed by a competing load serving entity is only offered by an IOU to the market after a compliance deadline, that IOU's shareholders should be assigned the financial responsibility for the competing load serving entity's RA penalties. As with the wasteful use of any IOU resource, the IOU shareholders should pay the costs and penalties, rather than burdening bundled or unbundled customers with these costs.

2. The value of Unsold RA in the true-up should be tied to the presence of a floor price in IOU solicitations.

POC supports CalCCA's proposal to value RA that is offered during the first annual solicitation period but not sold at the floor price of the solicitation, or zero if there is no floor price. PG&E does not support this requirement.[10]

The floor prices used in IOU solicitations are not known to market participants. At the May 16, 2019 meeting, CalCCA explained that the floor price calculations are a black box to the CCAs. In response, PG&E provided a vague description of the principles underlying its floor price. This description does not assuage POC's concern that the IOUs are using all the means available to them, including floor prices, to withhold RA from competing load serving entities. The requirement to set the value of unsold RA at the solicitation's floor price will provide a

[10] May 16, 2019 Presentation, at p. 19; *Id*. at p. 34; *Id*. at p. 44.

financial incentive for IOUs to sell, rather than withhold, excess RA from competing load serving entities. The Commission should approve CalCCA's proposal because it aligns all ratepayers' interests in an efficient allocation of RA resources with the IOUs' financial incentive to keep rates low for bundled customers.

3. Unsold RA in the Energy Resource Recovery Account Forecast should be set at a non-zero value.

The co-chairs agree on the quantity of unsold RA to include in the Energy Resource Recovery Account Forecast, but not the price of the unsold RA. PG&E proposes that all unsold RA be valued at zero, while CalCCA only supports using a zero value if a floor price is used in the true-up, as described in Section 2 above.[11] POC opposes both proposals and recommends using a non-zero value for unsold RA.

As explained above, POC has serious concerns about the IOUs' failure to offer excess RA at a reasonable time under reasonable terms. Unless and until an effective portfolio optimization mechanism is implemented, IOUs have an incentive to continue their practice of withholding their excess RA from the market at reasonable terms. Using a non-zero value in the forecast would send a signal to the IOUs that they must seriously embark on a program to sell all excess resources under reasonable terms, or their bundled customers will lose some of the value of these resources.

III. Unsold Renewable Portfolio Standard ("RPS") resources in the True-up

The co-chairs agreed that any sold RPS product should be valued at the transaction price, but they did not agree on the value of unsold RPS. POC agrees that sold RPS should be valued at the transaction price.

[11] May 16, 2019 Presentation, at p. 17; *Id*. at p. 32.

CalCCA proposes to value unsold RPS at the price of the final RPS Adder.[12] PG&E proposes breaking unsold RPS into two categories: RPS that is offered for sale but goes unsold ("Unsold RPS"), and RPS that is not offered for sale and is retained by the utility ("Retained RPS").[13] PG&E proposes that unsold RPS would be valued at zero, while Retained RPS would be valued at the price of the final RPS Adder.[14]

A. Unsold RPS resources must be priced based on their actual value instead of allowing IOUs to pick their value.

Without properly pricing unsold RPS based on its value, PG&E would benefit if it retains only the resources with the most desirable characteristics, and sells only the resources with the least desirable characteristics. In this scenario, the retained and desirable resources are valued at the RPS adder's average market price, which is below their actual value. The least desirable resources are sold and valued at the price of the transaction. In this scenario, both the retained and sold resources are valued at less than the RPS Adder's average market price. The desirable resources are not offered to other load serving entities for sale, are priced below their actual value, and are priced below the RPS Adder's average market value.

The Commission should not allow the IOUs this discretion to lower the value of their RPS resources. When children split a piece of pie, a parent tells them that one child divides the dessert and the other picks the piece that they find most desirable. The same concept applies to RPS sales: the IOUs should not get to cut the pie by choosing what quantity of resources to sell, and then choose which pie slice they receive by selecting the most desirable resources to retain. PG&E proposes that IOUs should be able to divide the portions and also select the most

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[12] May 16 Presentation, at p. 45.

[13] *Id*. at 38.

[14] *Id*.

desirable resources. The Commission should play the role of the parent, check the actions of its self-oriented utilities, and ensure that its rules lead to the fair pricing and allocation of RPS resources.

B. POC's proposal fairly values all unsold RPS resources.

To fairly value the resources, either all IOU resources should be offered for sale and valued at the transaction price, or any retained resources should be valued at the original contract price. If the IOUs have resources so valuable that they refuse to offer them for sale, then the resources should be valued at the original contract price. If an IOU does not want its existing RPS resources to be automatically valued at the original contract price, then the IOU should offer to sell all of its resources.

Under POC's proposal, an IOU is not required to transact all of the resources it offers for sale. Instead, an IOU could select to retain a portion of its resources offered for sale. For example, the IOU could select in advance to retain 40 percent of its resources while offering all of its resources for sale. If market participants bid on all of the resources offered, the 40 percent of resources receiving the lowest bids are retained by the IOU and valued in the true-up at the highest price market participants were willing to bid. If a resource receives no bids, it is valued at the price of the RPS Adder.

This system is similar to the dispatch order for generators in wholesale markets. While all generators bid into the market, only the resources collectively forming the least-cost solution for ratepayers are selected. The same is true of POC's RPS bidding proposal: all IOU RPS resources are offered, and only the bids forming the least-cost solution for ratepayers, *i.e.,* the highest bids, are accepted.

Finally, to keep the IOUs from reserving an overly large percentage of RPS resources, the resources retained by the IOUs must be used to serve bundled load. Any retained resources not used to serve customer load would be labeled as IOU excess resources. The cost of IOU excess resources are the responsibility of IOU shareholders because they are not used and useful in serving either bundled or unbundled customers. These costs are properly allocated to shareholders, as the costs result from the IOU's decision to prevent the sale of the IOU excess resource.

IV. Conclusion

The Commission should issue an interim decision regarding the issues discussed in these comments, and revisit these issues when the Commission acts on Working Group 3's portfolio optimization recommendations.

POC supports including CPM costs and revenues in the RA Adder. Unsold RA in the Energy Resource Recovery Account Forecast should be set at a non-zero value. The quantity of Unsold RA in the true-up should be established in this proceeding, and the Commission should establish shareholder responsibility mechanisms for IOUs unreasonably withholding RA from competing load serving entities.

Unsold RPS resources must be priced based on their actual value instead of allowing IOUs to pick their value. POC provides a proposal that fairly values all unsold RPS resources at a price set by the market.

POC thanks the co-chairs for their diligent work and presentation of complex issues to the Working Group.

DATED: May 29, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (filed June 29, 2017)

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 1 WORKING GROUP DRAFT FINAL REPORT

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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May 29, 2019

INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 1 WORKING GROUP DRAFT FINAL REPORT

TURN offers the following informal comments on aspects of the Working Group 1 Co-Lead Proposal emailed by PG&E on May 20, 2019. Citations are made herein to this Proposal and to the presentation the co-leads made May 16, 2019 in the third meeting of Working Group 1.

I. UNSOLD RA QUANTITIES AND PRICES

WG #1 leads appear to agree broadly on the identification of "retained," "sold" and "unsold" RA quantities. Similarly, WG #1 leads also appear to agree broadly, but not exactly, that any RA an IOU sells or retains for its use should be valued for PCIA purposes. PG&E and CalCCA made separate proposals for identifying the amount of RA capacity that is considered unsold. TURN does not endorse either proposal at this time, but notes that the IOUs should have some obligation to make RA available on a known schedule and terms though not necessarily at the "earliest annual auction" as CalCCA has proposed. The specific obligation of IOUs to make RA available through regular scheduled auctions should be addressed fully in WG #3.

Regardless of the specific rules differentiating "retained," "sold" and "unsold" RA capacity, the RA MPB should not be applied to any quantities of RA that are beyond LSEs' aggregate RA needs, as is the case in many months. Any guidance on IOU RA sales should be carefully written to provide IOUs incentives to sell surplus RA and to avoid providing IOUs any disincentives to put RA resources up for sale.

With respect to pricing, CalCCA may be correct that some number greater than zero may be appropriate for valuing the IOUs' unsold RA capacity. However, it is not clear that the "price floors" the IOUs may include in their RA sales protocols are an appropriate estimate of such values.[1] If a value greater than zero is to be imputed, further review of the IOUs' "price floors" – or other possible metrics – would be necessary.

II. LOCAL RA FORECAST AND FINAL ADDERS

WG #1 co-leads have proposed that, unless a central buyer structure for procuring RA is adopted, the Final Adder for Local RA should equal the Forecast Adder for Local RA. This approach would eliminate any true-up of the Local RA benefits and costs. While TURN recognizes that this recommendation may have been driven by the timing of Local RA transactions under the Commission's new multi-year forward procurement requirement, the final Working Group report should include some discussion about this proposal's consistency with the intent of D.18-10-019.

III. CPM PRICE SHOULD NOT BE INCLUDED IN LOCAL RA ADDER

CalCCA argues that "CPM costs assessed to LSEs are a cost for procuring RA and are appropriately included in the MPB". Co-lead PG&E disagrees.[2] TURN believes that CPM costs should <u>not</u> be included in the Market Price Benchmark (MPB). The language of D.18-10-019 specifies that CPM costs are not to be included in the MPB for capacity.[3]

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[1] For example, based on discussion at the May 16 WG #1 workshop, TURN understands that the price floors PG&E uses in its RA sales process reflect its estimate of the costs it may occur under the CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM) if such units do not perform in CAISO markets. TURN understands that though PG&E may sell RA capacity to parties and that such parties may use such capacity to comply with RA requirements, PG&E cannot (or does not) shed its Scheduling Coordinator obligation related to the RA capacity it sells, leaving PG&E exposed to the performance risks of the RA capacity it sells. If TURN's understanding is correct, PG&E's floor prices may not be a reasonable estimate of the market value of such resources.

[2] WG1 draft report, pages 13-14; WG1 co-lead presentation, May 16, 2019, page 43.

[3] For example, the Commission said "We are not persuaded that any of the alternatives proposed represent a better capacity benchmark than the RA Report" (p. 152) in response to some parties' proposals for alternate capacity price benchmarks (pp. 149-150), including CalCCA's specific proposal that "75% of the Local RA capacity would be valued at the weighted average CAISO CPM price" (p. 149).

Further, it is often not the case that "CPM costs are a cost for procuring RA". In many cases, the CAISO invokes CPM to purchase capacity even when LSEs have fully complied with their RA requirements.[4]

IV. UNSOLD RPS QUANTITIES AND PRICES

The two co-leads offered differing proposals regarding the classification of RPS resources. PG&E proposes that RPS resources be classified between "retained," "sold" and "unsold". CalCCA proposes that there be no RPS considered "unsold," that is, the IOUs' RPS volumes would either be considered as "retained" (to include "unsold" volumes) or "sold." PG&E generally argues that RPS volumes should be valued for PCIA purposes as they are used for compliance purposes ("retained") or sold to other parties ("sold") and that "unsold" volumes would not be assigned a value. CalCCA proposes that all of the IOUs' retained RPS volumes should be valued at the MPB, including those PG&E classifies as "unsold."

TURN believes RPS volumes should generally be valued as they are used or sold, consistent with PG&E's proposal. It is conceivable that the IOUs may retain RPS for contingency or other purposes (as is the case with RA); in such cases, a *de minimis* price may be appropriate to value such resources for the PCIA. TURN does not believe this issue was explored in the workshop process.

If the CalCCA proposal is adopted, a clarification must also be adopted that the proposed valuation of unsold RPS for PCIA purposes will occur once and only once. Once a value has been imputed to a unit of unsold RPS for a single PCIA computation, no other adjustments will be imputed to that unit of unsold RPS in any future PCIA

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[4] For example, in the *2018 Annual Report on Market Issues & Performance* (Report), the CAISO's Department of Market Monitoring notes that CPM may be invoked on time frames from intra-monthly to annual and for purchases needed to address a "collective deficiency" or significant events or to make an "exceptional dispatch". See p. 251 of the Report, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

computation. With this principle, CalCCA's proposal would result in all unsold RPS volumes being valued at the MPB in the first year this method applies and no further valuations of such RPS volumes would be made for PCIA purposes in future years.

V. CONFIDENTIALITY ISSUES

The draft final report references concerns relating to confidentiality protections for commercially sensitive data used to develop the market price benchmarks.[5] TURN believes that the submission of confidential data pursuant to the requirements of D.06-06-066 and D.08-04-023 should be sufficient to protect against public disclosure. Given the changes in retail markets and the growth of both CCA and Direct Access loads, the Commission should provide non-market participants (NMPs) with equal access to confidential information submitted by CCAs, ESPs and IOUs. Since the confidential material used to develop the MPBs will have an impact on all ratepayers, there is no reason to restrict access only to ED staff.

The Commission previously found that TURN and other NMPs should be able to access confidential materials submitted by ESPs. In D.06-06-066, the Commission rejected efforts to prevent NMPs from accessing confidential materials. Specifically, the Decision orders access to any confidential information by NMPs as follows:

> *Intervenor groups that are non-market participants shall not be precluded from access to any ESP or IOU data as long as they agree to a protective order or confidentiality agreement where there is a need to protect the data.*[6]

This principle should be reiterated in the current proceeding with the clarification that the right of NMPs to review confidential material extends to all LSEs. The Commission should clarify in any final decision in this proceeding that the access rights established

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[5] WG1 draft report, page 15.
[6] D.06-06-066, pages 58-59, Ordering Paragraph 11.

in D.06-06-066 remain in force and direct the parties to develop a common non-disclosure agreement (NDA) that can be used for confidential materials submitted by any ESP, CCA or IOU relating to the development of the MPBs. The use of a single NDA would minimize the burden of negotiating and executing dozens of individual agreements and ensure equal access to all confidential materials. The common NDA should be proposed by the parties, adopted by the Commission, and updated in future proceedings as appropriate.

VI. RELIANCE ON INDEX-BASED TRANSACTIONS FOR RENEWABLE ENERGY COSTS

The draft final report notes the exclusion of any fixed price renewable energy transactions from being used to develop the MPB.[7] The slide presentation at the May 16 workshop provides additional justifications for the exclusion including the absence of any showing that fixed price transactions represent "the majority of current RPS transactions."[8] Moreover, the slide presentation notes that bundled renewable energy transactions may yield "unexpected results" including "$0 or negative PCC1 REC prices".[9] TURN disagrees with the rationales cited by the co-leads.

As explained in TURN's prior comments, the reliance on "index-plus" transactions could lead to skewed benchmarks given the potential disconnect between short-term prices for surplus output from existing projects and the long-term pricing for newly developed renewable resources.[10] Given the heavy reliance on long-term fixed price agreements for newly built resources, and the statutory requirement that 65% of all RPS compliance be sourced under long-term agreements beginning in 2021, the categorical exclusion of fixed-price transactions from the MPB would be extremely problematic.

[7] WG1 draft report, pages 15-16.
[8] WG1 co-lead presentation, May 16, 2019, page 51.
[9] WG1 co-lead presentation, May 16, 2019, page 51.
[10] See TURN's March 7th comments, pages 1-4.

TURN believes that the failure to consider these transactions could skew the MPB and result in renewable adders that materially diverge from the imputed renewable premiums reflected in a large volume of actual market transactions.

In response to significant engagement by the co-leads, TURN put forward a proposal to require all LSEs to submit data to ED detailing all fixed price bundled renewable energy transactions. The details of TURN's proposal were circulated on May 21 for comment by other stakeholders.[11] This proposal should be included in the final WG1 report for consideration by the Commission.

TURN appreciates the chance to submit these comments.

Respectfully submitted,

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Dated: May 29, 2019

[11] TURN proposal for incorporating fixed-price bundled renewable energy transactions into the MPB analysis, May 21, 2019.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternative to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF THE UTILITY CONSUMERS' ACTION NETWORK (UCAN) ON THE UTILITY REFORM NETWORK'S (TURN's) ALTERNATIVE MPB PROPOSAL FOR WORKING GROUP 1

UCAN
UTILITY CONSUMERS' ACTION NETWORK
San Diego's Utility Watchdog

May 29, 2019

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INFORMAL COMMENTS OF THE UTILITY CONSUMERS' ACTION NETWORK (UCAN) ON THE UTILITY REFORM NETWORK'S (TURN's) ALTERNATIVE MPB PROPOSAL FOR WORKING GROUP 1

The Utility Consumers' Action Network (UCAN) appreciates the opportunity to comment on the "TURN proposal for incorporating fixed-price bundled renewable energy transactions into the Market Price Benchmark (MPB) analysis" released on May 21, 2019.

UCAN supports TURN's observations and recommendations that:

1. *"[Comparing] the market price for energy and RA from renewable generation with different technologies and locations*" is challenging;
2. The revisions proposed to the current MBP methodology were formulated on an expedited basis "[*given] the need for prompt action on the development of a methodology that can be implemented this year*";
3. Key issues are being further evaluated under Working Group 3 (i.e. on a less expedited timeline that allows for more informed deliberation and analysis);
4. Consequently, to assess the validity of the PCIA methodology on an ongoing basis, additional data should be collected covering "*each fixed-price bundled transaction should include price, contract duration, delivery node, hourly delivery profile and Resource Adequacy value*"
5. Subsequently, that "*the Commission set an explicit sunset date for using the BP+REC pricing model at which time one or more models for estimating the market prices of RPS-eligible energy contracts could be considered."*

UCAN would additionally emphasize that the specific issues highlighted by TURN in the alternative proposal, and the consequent recommendations — particularly that additional data on delivery nodes, generation profile, et cetera, should be collected for PCIA-eligible transactions — underscore a broader challenge facing Working Group 3.

Portfolio optimization cannot credibly be construed any longer simply as an exercise in wholesale generation cost-averaging, much less one focused on a subset of a wholesale portfolio (i.e. PCIA-eligible contracts). Doing so implicitly ignores:

1. How the same assets may be valued — and operated — differently by LSEs according to their unique risk profiles and risk management practices (including what the hedge and option value of such assets is worth for an LSE given those unique considerations);
2. How extant retail load profiles, on an individual customer and aggregated basis, vary widely across geographies and should be shaped intelligently in response to price signals (e.g. through dynamic retail rates and services that enable DER integrations);
3. How retail load patterns are regardless shifting and diverging rapidly in specific locations (due to the acceleration of DERs, natural gas fuel-switching and vehicle electrification);
4. How distribution grid network constraints and stranded costs could be lowered or avoided by incorporating Distribution Marginal Costs on a de-averaged basis into planning and tariff-based procurement, unbundling services like customer voltage, VAR and more granular power quality metrics in the process;
5. How zonal resource adequacy generation capacity requirements, the ramping dynamics therein, localized gas system constraints that distort regional electricity market price signals, et cetera, could be best met through similar demand-side strategies.

These examples, and many other sources of risks, costs and corresponding demand-side strategies that can mitigate challenges across the different upstream dimensions of the electricity system, ultimately combine to define the cost-of-service for all customers in California. Current methodologies are increasingly obsolete, unable to properly assess the best way forward, and have recently begun to undermine the perception of California's ability to competently manage costs and ensure reliability while pursuing its decarbonization goals.

Given the present-day realities in California, actual "portfolio optimization" necessitates a de-averaging approach, which assesses the co-optimization potential for shifting retail load and DER impacts in a manner that lowers costs and risks across upstream dimensions of the system. This in turn necessitates the use of highly-granular locational and temporal data to inform the use of advanced planning software and corresponding day-to-day operational processes. Before that can begin to happen, this requires the recognition and removal of regulatory practices that currently prohibit stakeholders from pursuing or even discussing intelligent solutions to a meaningful degree.

Ignoring these new realities — e.g. by continuing to rely on average inputs to inform supply-oriented models and spreadsheets to "optimize" a subset of a generation portfolio exclusively in terms of wholesale risk and cost factors — by definition will be both riskier and costlier for ratepayers than a portfolio which has been co-optimized across the different "siloes" of the energy sector.

Failing to implement a systemic approach to portfolio optimization will result in less social value (i.e. opportunity cost) and stranded costs. Moreover, continuing the practice of forcing customers who contribute relatively less to load growth, ramping, high peak loads, et cetera to subsidize customers who are actively driving those costs up raises serious equity concerns that have received little, if any, attention to-date.

Thus, UCAN believes that TURN's recommendation to routinely collect and analyze more temporally- and geographically-granular data for PCIA-eligible transactions is a step in the right direction.

UCAN appreciates the opportunity to file these informal comments.

Date: May 29, 2019

Respectfully Submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON THE PCIA OIR: WORKING GROUP 1 – DRAFT END-TO-END BENCHMARK AND TRUE-UP PROPOSAL

May 29, 2019

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CLECA
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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON THE PCIA OIR: WORKING GROUP 1 – DRAFT END-TO-END BENCHMARK AND TRUE-UP PROPOSAL

The California Large Energy Consumers Association (CLECA)[1] has members that are bundled customers, direct access customers, and customers of community choice aggregators (CAAs). Therefore, an equitable calculation of the Power Charge Indifference Amount (PCIA) is important to our members. CLECA comments on the PCIA Working Group 1: End-to-End Benchmark and True-up Proposal distributed by the co-leads on May 20, 2019. The working group co-leads requested informal comments by May 29, 2019, which will be attached to the submission of final working group report on May 31, 2019.

[1] CLECA is an organization of large industrial electric customers of Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE); the member companies are in the steel, cement, industrial gas, mining, pipeline, cold storage, and beverage industries and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite generation. CLECA has been active in Commission proceedings since the early-to-mid 1980s and strives for even-handed treatment of all customers.

1. Unsold RA capacity should be valued at a zero or *de minimis* value

The Commission in the decision reforming the PCIA calculation ordered "a zero or *de minimis* price shall be assigned for capacity expected to remain unsold".[2] The California Community Choice Association (CalCCA) seeks to define zero or *de minimis* as the price floor on any unsold capacity.[3] This would be inappropriate. One issue in determining a price floor is the transaction costs, but there may be other factors that impact a price floor, and the utilities mentioned this information is market sensitive. If resources remain unsold at the price floor, then there is either excess capacity or the resource has attributes that are not desirable. CalCCA's recommendation to set the value of unsold capacity at the price floor could create a perverse incentive for the utilities to set the price below a reasonable price floor, which would in turn create a subsidy to the entity purchasing the capacity.[4] This could create inequities between CCAs and ESPs that are fully resourced and those that require capacity. That subsidy would then be paid by the customers of non-utility LSEs. The result of extremely low RA prices could undermine the bilateral RA market for non-utility resources. CLECA supports the Commission decision and its order to use a zero or *de minimis* value which could be a value of less than 10 percent of the RA Adder.

2. The end-to-end proposal fails to true up the Local RA capacity adder

The end-to-end proposal states that the "Inputs into the Final RA Adder for local RA will remain the same as for the Forecast RA Adder, unless a central buyer structure is adopted."[5]

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[2] CPUC D.18-10-019, Ordering paragraph 1c, at 160.
[3] PCIA OIR: Working Group 1 – DRAFT End-to-End Benchmark and True-up Proposal at 4, 5, 7, 8, and 14.
[4] The IOUs should work with the procurement review groups and Energy Division to justify that their price floors are reasonable.
[5] PCIA OIR: Working Group 1 – DRAFT End-to-End Benchmark and True-up Proposal at 7

This is contrary to the goals of the PCIA decision, which seeks to true up forecasts with actual values. The current procurement requirement for Local RA is 100% in years 1 and 2, and the annual showings occur in the fourth quarter prior to year *n*, so the forecast local RA will incorporate actual transactions. However, this does not mean that for year *n*, monthly transactions of local RA between the annual showing do not occur. There could be multiple reasons for intra-annual transactions, such as replacement of local RA or transactions associated with load migrations. CLECA does not support the co-leads' recommendation not to true up the local RA adder. Instead, the Local RA true-up should include transactions in year *n*.

3. CAISO's Capacity Procurement Mechanism price does not represent market transactions and should not be used in market price benchmark for RA

CalCCA's support of the CAISO's Capacity Procurement Mechanism (CPM)[6] in the market price benchmark for RA Adder contradicts the clear language in the Commission decision updating the PCIA calculation-directed use of TURN's RA Adder:

> we adopt TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n). A zero or de minimis price shall be assigned for capacity expected to remain unsold.[7]

TURN's RA Adder did not include use of the CPM. Moreover, in response to CalCCA's proposal to use the CPM to benchmark capacity, CLECA's testimony in R. 17-06-026 explained why the CPM price is not appropriate for use in the RA Adder or for benchmarking capacity costs:

> Reliability Must Run and CPM contracts are used for backstop when resources that are not contracted for RA are determined through power flow studies to be needed for reliability. Market prices for capacity have been dampened by the existence of excess capacity procured for policy reasons other than capacity value, such as RPS procurement.

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[6] PCIA OIR: Working Group 1 – DRAFT End-to-End Benchmark and True-up Proposal at 14.
[7] D. 18-10-019, at 73.

> CalCCA proposes to use the soft offer cap for the CAISO's backstop CPM that is used in cases of RA resource deficiency (most recently in local capacity areas or subareas), exceptional dispatch (e.g. for a transmission emergency), or for significant events (unexpected conditions like the shut-down of the San Onofre Nuclear Generating Stations (SONGS)). It can be used for as little as 30 days or as long as a year. This is the going forward fixed cost of a 550 MW combined cycle plant with duct firing plus a 20% adder. It is currently $75.68/kW-year. The CPM is only used in the case of a deficiency, which is for the CAISO occasioned by a reliability concern. Thus, by its very nature, if a resource is procured through the CPM, it is not surplus capacity. Furthermore, the soft offer cap has become something of a floor, since recent CPM procurement has occurred at values very close to the soft cap. For these reasons, I do not support its use as proposed by CalCCA as a value for surplus capacity, nor do I support CalCCA's determination of surplus capacity.[8]

CLECA continues to oppose these efforts to include the CPM in the market benchmark price, and we reiterate that the working group process should not be subverted into re-litigation of issues already decided by the Commission. D. 18-10-019 is clear that the RA Adder is to be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions"; this does not include use of a CAISO administratively-determined price, e.g., the CPM.

4. Unsold Renewable Portfolio Standard Credits have zero value

CalCCA supports valuing unsold Renewable Portfolio Standard (RPS) Credits at the RPS benchmark, as they consider the credits retained.[9] Similar to the issue of unsold RA, this would create undesirable incentives to artificially lower RPS credit value and would result in subsidy to purchasers buying RPS at depressed prices. CLECA does not support CalCCA's recommendation.

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[8] Ex. CLECA-1 in R. 17-06-026, Testimony of Dr. Barbara R. Barkovich, at 12.
[9] PCIA OIR: Working Group 1 – DRAFT End-to-End Benchmark and True-up Proposal at 15.

Respectfully submitted,

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May 29, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338 E) INFORMAL COMMENTS ON PCIA PHASE 2 WORKING GROUP ONE BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUESMAY 16, 2019 MEETING #3 WORKSHOP PRESENTATION

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338 E) INFORMAL COMMENTS ON PCIA PHASE 2 WORKING GROUP ONE BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUESMAY 16, 2019 MEETING #3 WORKSHOP PRESENTATION

I.

INTRODUCTION

Southern California Edison Company (SCE) appreciates the thoughtful and extensive work to date by Working Group 1 Co-Leads California Community Choice Association (CalCCA) and Pacific Gas and Electric Company (PG&E), as well as this opportunity to submit informal stakeholder comments on that work. Specifically, SCE is submitting for consideration these brief informal comments on one discrete issue, the appropriate use of certain previous years' transactions in setting and true-up the "local" Resource Adequacy (RA) capacity benchmarks. SCE appreciates the Co-Leads' consideration of these informal comments on this issue set forth in the Co-Leads' May 16, 2019 Working Group Workshop Report (Report).

II.

SCE INFORMAL COMMENTS ON WORKSHOP REPORT

A. The Transactions Used to Set Future Local RA Benchmarks Should Reflect the Underlying Market Structure Associated with the Applicable Regulatory Requirements

On Slide 26 of the Report, the Co-Leads have proposed that starting in 2021 the forecast RA Local Capacity Adder should be set using data from transactions executed in Year N-2 for delivery in Year N. The Commission's new Local multi-year RA rules require Load-Serving Entities (LSEs) to demonstrate RA compliance in delivery Year N for 100% of the LSE's needs for Year N+1 and Year N+2, and 50% of the LSE's needs for Year N+3. SCE believes the transactions that inform the benchmarks should match the market transactions that are required by the new rules. As currently written, the Co-Leads' proposal would omit potentially the majority of relevant transactions from the Local capacity benchmark, and create an unnecessary mismatch between the forecasts and subsequent true-ups. Accordingly, SCE proposes that the benchmark should consider the relevant transactions from *both* Year N-2 and Year N-3 for the Local capacity benchmark starting in 2021.[1]

III.

CONCLUSION

SCE appreciate the Co-Leads' consideration of these informal comments and looks forward to working with the working group through the completion of the process.

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[1] SCE recognizes that such a change would require a formal modification of D.18-10-019 (which only contemplated using N and N-1 values), but so would the Co-Leads' current proposal (which also contemplates using N-2 values). SCE believes that both proposed changes are consistent with the rationale underlying the original final decision.

Respectfully submitted,

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May 29, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) ON THE PHASE 2, WORKING GROUP 1 PROPOSAL

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May 29, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) ON THE PHASE TWO, WORKING GROUP ONE PROPOSAL

I. INTRODUCTION

In accordance with the schedule established for Phase Two, Working Group One, San Diego Gas & Electric Company ("SDG&E") provides the following informal comments concerning the Power Change Indifference Adjustment ("PCIA") benchmark and true-up proposal ("Proposal") presented by Working Group One.

Working Group One, led by co-leads, Pacific Gas and Electric Company ("PG&E") and the California Community Choice Association ("CalCCA") (together, the "Co-Leads"), was tasked with developing a detailed process for forecasting and truing-up PCIA-benchmarks, including the brown power component, the resource adequacy ("RA") adder, and the renewables portfolio standard ("RPS") adder. While Working Group One collaborated effectively and was successful in reaching consensus on many details regarding the benchmark and true-up process, limited areas of disagreement remain. Four specific areas of disagreement are identified and discussed in joint comments concurrently submitted by PG&E, SDG&E and Southern California Edison Company ("SCE"). In the instant comments, SDG&E identifies an additional area of concern regarding the Proposal. Specifically, SDG&E submits that the methodology proposed for establishing the Local RA adder may result in an impermissible cost shift to bundled service customers and is inconsistent with the proposal for the System and Flexible RA true-up adders.

II. DISCUSSION

The Public Utilities Code explicitly prohibits a cost increase to remaining bundled service customers caused by load departure.[1/] Thus, the Commission must ensure that the adopted benchmark and true-up proposal is designed to prevent such cost shifts.

The Proposal's approach to defining the Local RA adder creates an impermissible cost shift to bundled service customers. In addition, the proposed Local RA adder methodology is inconsistent with the proposal for defining the System and Flexible RA true-up adders. Accordingly, as discussed below, the Commission should adopt a true-up methodology for the Local RA adder that (i) includes all transactions utilized in the forecast Local RA adder, as well as additional transactions executed in Q1 through Q3 of year n for delivery in year n; and (ii) includes transactions in year n-3 in the market price benchmark ("MPB") calculation.

The Proposal details the datasets of market transactions that will be used to calculate the various forecast and true-up RA adders. These datasets are summarized in Table 1 below:

TABLE 1

	System and Flex RA	Local RA
Forecast RA Adder Dataset	Transactions executed in Q4 of n-2 and Q1-3 of n-1 for delivery in year n.	**2020**: Transactions executed in Q4 n-2 and Q1-3 of n-1 for delivery in year n. **2021 and Beyond:** Transactions executed in n-2 and n-1 for delivery in year n.
True-Up RA Adder Dataset	Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n.	*Same as forecast*

[1/] *See, e.g.*, Cal. Pub. Util. Code § 366.2(a)(4) ("The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."); §366.2(d)(1) ("It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers."); §365.2 ("The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.").

SDG&E's primarily concern with this proposal is that the Local RA adder used for true-up purposes is calculated based on the *same* transaction dataset as is used to develop the forecasted Local RA adder;[2/] the dataset is not updated to reflect transactions that occur in year n. As a practical matter, excluding year n transactions means that the RA adder is static. There is no difference between the benchmark and the data used for true-up purposes, and therefore no real true-up. The lack of true-up was a major deficiency in the prior PCIA methodology and is a critical improvement of the new methodology. An effective true-up is essential to ensure compliance with the statutory prohibition on cost-shift to bundled service customers.

The proposed methodology for defining the Local RA adder is also inconsistent with the approach used to true-up System and Flexible RA. Whereas the true-up process for Local RA under the Proposal includes transactions made in year n-2 and year n-1 for delivery in year n, but does not include year n transactions, the true-up process for System and Flexible RA involves use of updated market transactions, inclusive of year n, to calculate the MPB.

To ensure compliance with the statutory cost indifference requirement, as well as internal consistency in the benchmarking and true-up process, SDG&E recommends that the Commission adopt a true-up methodology for the Local RA adder that includes all transactions utilized in the forecast Local RA adder, as well as additional transactions executed in Q1 through Q3 of year n for delivery in year n. This would (i) ensure the Local true-up RA adder is representative of updated transactions in the bilateral market; (ii) maintain indifference in the portfolio costs for bundled service and departed customers; and (iii) maintain consistency with the proposed methodology for System and Flexible true-up RA MPBs.

[2/] WG1 Draft Final Report, p. 7 ("Inputs into the Final RA Adder for local RA will remain the same as for the Forecast RA Adder, unless a central buyer structure is adopted.").

Secondly, in light of Decision ("D.") 19-02-022, which established multi-year Local RA requirements for load-serving entities ("LSEs"), SDG&E believes that LSEs may be procuring Local RA capacity for compliance year 2022 (year n) in 2019 (year n-3). Accordingly, transactions in year n-3 should also be included the MPB calculation. The proposal currently only includes transactions executed in year n-2 and year n-1, but not year n-3. This omission calls into question whether the MPB will reflect the true bilateral market.

SDG&E's proposed changes to the RA adders are summarized in Table 2 below.

TABLE 2

	System and Flex RA	Local RA
Forecast RA Adder Dataset	Transactions executed in Q4 of year n-2 and Q1-Q3 of year n-1 for delivery in year n.	Transactions executed in Q1 of year n-3 through Q3 of year n-1 for delivery in year n.
True-Up RA Adder Dataset	Same transactions used in the Forecast RA adder plus transactions executed in Q4 of year n-1 and Q1 – Q3 of year n for delivery in year n.	Same transactions used in the Forecast RA adder plus transactions executed in Q4 of year n-1 and Q1 – Q3 of year n for delivery in year n.

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Respectfully submitted this 29h day of May, 2019.

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP MEETING #4 AND DRAFT END TO END BENCHMARK AND TRUE-UP PROPOSAL

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May 29, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP MEETING #4 AND DRAFT END TO END BENCHMARK AND TRUE-UP PROPOSAL

The Alliance for Retail Energy Markets[1] and Direct Access Customer Coalition[2] (collectively referred to herein as "AReM/DACC") continue to appreciate the leadership of PG&E and CalCCA in Workgroup #1. AReM/DACC welcomes this opportunity to comment on the issues raised at the Working Group's fourth meeting on May 16. We continue to be optimistic that the parties will be able to reach consensus on many of the thorny issues that have been so well laid out.

Pacific Gas and Electric ("PG&E") and the California Community Choice Association ("CalCCA") are the Co-Leads for Working Group 1. With the exceptions and comments laid out below, AReM/DACC concur with the Co-Lead's draft proposal presented at the May 16 Workshop and the "DRAFT End to End Benchmark and True-up Proposal" provided to the service list on May 17.

[1] AReM is a California mutual benefit corporation formed by Electric Service Providers ("ESPs") that are active in California's Direct Access retail electric supply market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access for all or a portion of their electrical energy requirements.

I. TREATMENT OF UNSOLD RESOURCE ADEQUACY (RA) CAPACITY

AReM/DACC note the two Co-Leads do not concur with respect to the treatment of "unsold" RA, or more specifically, how unsold RA would be valued when calculating the true-up of the RA adder. AReM/DACC understand "unsold" RA to be (a) RA product(s) that were offered for sale by the incumbent investor-owned utility (IOU) but not purchased by another LSE. Furthermore, the offering of RA by the IOU had to occur in a time that other LSEs could reasonably acquire it for RA compliance (i.e., the sale cannot occur immediately before, or after, the applicable RA compliance period. PG&E proposes that this unsold RA be valued at "zero;" i.e., no credit would be included for that RA when truing up the RA adder/value. CalCCA proposes, pending any resolution of this issue in Working Group #3, the unsold RA "will be imputed a value equal to the IOUs' price floor (if there is one), or zero (if no floor) for amounts that are offered for sale in the first annual solicitation, but are not sold. Otherwise 'unsold' amounts are treated as retained and valued at the MPB."[3]

AReM/DACC concur with CalCCA's position: the RA should be valued at the floor price of any IOU offering (if any). This represents the minimum value that the selling IOU places on the RA and should be treated as such.

II. TREATMENT OF UNSOLD RENEWABLE PORTFOLIO STANDARD RECS CAPACITY

AReM/DACC also note the two Co-Leads do not concur with respect to the treatment of "unsold" RPS products, or more specifically, how unsold RECs would be valued when calculating the true-up of the adder. PG&E proposes that, "no revenue is recorded to PABA for RPS product that is offered for sale consistent with the IOU's RPS plan and remains unsold. If previously

[3] DRAFT End to End Benchmark and True-up Proposal, page 4.

unsold RPS is sold in a future year, it is valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it is valued at the applicable future year's RPS Adder."[4] CalCCA proposes that, "the volume of RPS retained by IOUs is under consideration in Working Group #3. Unsold RPS should be valued at the benchmark."[5]

Consistent with positions taken by AReM/DACC, we concur with CalCCA's position: RPS products (i.e., RECs) should be valued at the time that they are generated. Tracking how much is "consistent" with the IOU's RPS plan and valuing only when (or if) withdrawn from the RSP bank is unwieldy and opens the door to possible gaming.

III. COMMENTS ON THE DRAFT TEMPLATES

As noted in prior comments, AReM/DACC reiterate their recommendation to include contract price reporting for RA and RPS purchases only and exclude contract price reporting for RA and RPS sales, except when the sales data is from contracts pursuant to which an LSE under CPUC jurisdiction sells products to a non-CPUC jurisdictional entity, such as a municipal utility or irrigation district. This recommendation, too, should assist ED staff in calculating the benchmarks in a timely fashion.

Secondly, AReM/DACC note that the sample RA template does not appear to provide for reporting the MW of local RA under contract, only the local area. A row should be added for Local MW, similar to what is done for System and Flex RA.

Third, under "Volumes" for the RPS template, staff should clarify that forecasted volumes are what is desired to reflect the actual delivery expected from the contract. "Contracted" volumes

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[4] *Id.,* at page 8.

[5] *Id.,* at page 9.

could be very different than what is actually delivered if it only reflects an absolute minimum that the project will provide, and thus could skew the input basis for this contract.

Fourth, while AReM/DACC appreciate the complex task facing Energy Division in creating the various components of the market price benchmarks, we continue to minimize reporting requirements, specifically to, as quickly as possible, reduce the reporting to an annual filing from the Co-Lead's proposed quarterly filings.

IV. **CONCLUSION**

AReM/DACC thank the Working Group co-chairs for their hard work and look forward to reviewing other parties' comments.

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May 29, 2019

The City of
SAN DIEGO
Sustainability

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CITY OF SAN DIEGO INFORMAL COMMENTS ON DRAFT FINAL REPORT REGARDING BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

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Dated: May 29, 2019

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The City of SAN DIEGO
Sustainability

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CITY OF SAN DIEGO INFORMAL COMMENTS ON DRAFT FINAL REPORT REGARDING BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

Pursuant to the schedule established in the e-mail sent to parties to Rulemaking (R.) 17-06-026 on May 20, 2019, The City of San Diego (City) respectfully submits these informal comments on the draft final report regarding certain benchmark true-up and other benchmarking issues. The proposal, titled "End-to-End Benchmark and True-Up Proposal" (Proposal) addresses issues 1-7 that were to be addressed in Working Group 1 in Phase 2 of Rulemaking (R.) 17-06-026 (the PCIA proceeding).

The City appreciates all of the hard work that went into the development of the Proposal and the opportunity to provide comments to enhance the final report on issues 1-7 that the co-leads will be sending to the Commission on May 31, 2019, pursuant to the schedule established by the Commission in this phase of the PCIA proceeding.

The City has selected Community Choice Aggregation (CCA) as the preferred pathway to reach its 100 percent renewable electricity goal in the City's landmark Climate Action Plan. Recently, City Council approved a resolution to begin the process of establishing a Joint Powers Authority (JPA) to form a CCA. The CCA is expected to serve customers starting in 2021.

Given the state of the of the City's CCA efforts, the City's perspective is different than that of CCAs that are fully operational; the City's concerns with the Proposal are more closely related to those of a new CCA that is in the early phases of bringing on new customers. In addition, the City is different than some CCAs, in that it, is likely that the vast majority of the City's Resource

Adequacy (RA) obligations will consist of Local RA, meaning that the Commission's recent decision regarding the multi-year Local RA obligation (Decision (D.) 19-02-022) could have a significant impact on the City's CCA efforts.

Generally, the City agrees with the joint recommendations of the co-chairs in the Proposal. The City is pleased with the significant number of potentially contentious issues that the co-leads were able to resolve in the Proposal, including (1) the definitions of the three Market Price Benchmarks (MPBs), (2) the scope of each MPB (i.e., whether it applies to a single utility or to all utilities), (3) the choices of historic data to be used in both the forecast and true-up of the Brown Power Adder, the RA Adders, and the RPS Adders, and the revised role for the Energy Division in calculating the forecasted and final Adders.

Unfortunately, the co-chairs were unable to resolve all issues in the Proposal. The Proposal clearly spells out areas of disagreement between the co-chairs. The City's comments focus on areas of disagreement between the co-chairs.

Value of Unsold Resource Adequacy Capacity

There is a difference between the co-leads regarding the price and quantity of RA in the true-up.[1] PG&E believes that the price for actual unsold RA should be zero, while CalCCA recommends that the prices should be equal to Price floor used in the solicitation (if any) or zero if there is no price floor set by the IOU. PG&E believes that the quantity of actual unsold RA should equal the quantity offered for sale but not used by the IOU, while CalCCA believes that the quantity of actual unsold RA should equal the quantity offered for sale <u>in the first annual solicitation</u> but not sold.

The City supports adoption of the CalCCA position on the question of price for actual unsold RA. If an IOU offers RA but sets a floor price in its RFO, then that price should be the value of the actual unsold RA. The IOU has complete control over the setting of the floor price for its

[1] Proposal, p. 7 of 16.

RFOs; if it sets an unreasonably high floor price, then the floor price could very well be a major factor in the fact that the RA is unsold, meaning that the floor price is the clearing price for unsold RA. If the IOU does not set a floor price, then the price of unsold RA should properly be set at zero. Because of this, the CalCCA proposal regarding price of actual unsold RA is appropriate.

The City also supports the CalCCA proposal regarding the quantity of unsold RA to be used in the true-up. The CalCCA proposal requires the IOU to offer RA capacity in its first RFO if it wants to have that capacity potentially included in the actual unsold capacity quantity in the true-up. It avoids the possibility of an IOU offering RA capacity at the last minute after other LSEs have already finalized their plans based on an expectation from the first RA RFO that the IOU will NOT be offering RA. The CalCCA proposal limits potential gaming of the true-up mechanism by the IOUs. For that reason, the City supports the CalCCA proposal.

Value of Unsold RPS Energy

There is a difference between the co-leads regarding the value of unsold RPS energy in the true-up. PG&E proposes that "unsold" RPS be priced at zero in the annual true-up.[2] The volumes would be valued, however, if they are used later for compliance (i.e., in the three-year retirement period or out of the bank). CalCCA proposes that any unsold volumes be priced at the RPS benchmark.

The City finds CalCCA's proposal to be more reasonable. The true-up is an annual activity, meaning that the forecasted PCIA needs to be trued-up based on actions in the past year, not some undefined actions that might occur in the future. This is what CalCCA proposes. PG&E's proposal appears to have some sort of after-the-fact true-up based on future actions by the IOU. This would result in inter-temporal cross-subsidies. For that reason, the City supports the CalCCA proposal.

[2] Proposal, pp. 9-10.

Inclusion of CPM Backstop Procurement in the RA Adder

There is a disagreement between PG&E and CalCCA regarding whether CPM backstop procurement by the California Independent System Operator (CAISO) should be included in the RA adder. PG&E believes that CPM procurement should not be included as a cost in the RA adder, while CalCCA contends that the CPM procurement is a cost of RA procured on behalf of LSEs and should rightly be reflected in the RA benchmark.[3]

The City supports CalCCA's position on this issue. If an LSE is assigned costs by the CAISO associated with backstop procurement, then that cost is in fact a cost of RA for that LSE and reflects the cost of a portion of the LSE's RA portfolio. Under PG&E's proposal, the RA benchmark would effectively assume a zero price and zero quantity for the CAISO backstop procurement, which is clearly incorrect. For this reason, the City supports CalCCA's position on this matter.

Conclusion

The City appreciates all the hard work that went into the development of the Proposal and recommends that the Commission adopt the City's recommendations in its final decision regarding benchmark and true-up of the PCIA.

Dated: May 29, 2019.

Respectfully submitted,

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[3] Proposal, pp. 13-14.

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Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON WORKING GROUP ONE DRAFT END TO END BENCHMARK AND TRUE-UP PROPOSAL

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON WORKING GROUP ONE DRAFT END TO END BENCHMARK AND TRUE-UP PROPOSAL

California Community Choice Association (CalCCA)[1] submits the following informal comments on the Draft End to End Benchmark and True-up Proposal (Draft Proposal) prepared by the Co-Leads of Working Group 1 established by Decision (D.) 18-10-019.

I. INTRODUCTION

CalCCA is a co-lead of Working Group 1, along with Pacific Gas & Electric Company (PG&E; collectively with CalCCA, Co-Leads). The Draft End to End Benchmark and True-up Proposal (Draft Proposal) contains the Co-Leads' principles for valuing investor-owned utility (IOU) portfolios to set the Power Charge Indifference Adjustment (PCIA) and associated rates. In the Draft Proposal, the Co-Leads propose methods to forecast asset value in IOU portfolios for use in setting forecast PCIA rates. The Co-Leads also propose how to "true-up" PCIA rates to actual revenues and costs (where available) and to revised market price benchmarks (where actual transaction data are not available; e.g., where IOUs use portfolio assets to serve "bundled"

[1] California Community Choice Association represents the interests of 18 community choice electricity providers in California: Apple Valley Choice Energy, Clean Power SF, Clean Power Alliance, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

customers). The Draft Proposal largely contains consensus positions between the Co-leads, and CalCCA accordingly supports them.

Two areas of disagreement remain, however, which focus on the treatment of "unsold" Resource Adequacy (RA) and "unsold" Renewable Portfolio Standard (RPS) attributes. First, *when is RA deemed unsold for purposes of valuing the RA at a "zero or de minimis" price, and what price should be applied?*

- PG&E fails to propose clear guidelines for determining when RA can be deemed "unsold" pursuant to D.18-09-010 (PCIA Decision) and proposes that all "unsold" RA be valued at zero. This approach gives PG&E full discretion in handling valuable RA assets, for which departing load customers bear cost responsibility, and could place other load-serving entities (LSEs) in jeopardy for RA compliance obligations.
- CalCCA proposes clear guidelines, requiring that IOUs must offer RA to the market not later than the end of August preceding the compliance year. CalCCA further proposes that unsold RA must be valued at the IOU's solicitation price floor, where a price floor is used; if no price floor is used, the RA attributes will be valued at zero. This approach ensures the utility offers all "excess" RA sufficiently early to enable timely compliance by other LSEs who need the RA to meet their requirements, and the proposed pricing ensures that the implicit value of the attribute is recognized.

Second, *is there any justification for treating RPS that is "unsold" differently from other retained RPS attributes?*

- PG&E proposes to value unsold RPS attributes at zero unless and until the attributes are later sold (valued at the transacted price) or used for compliance (valued at the then-current market price benchmark).
- CalCCA proposes that *all* retained RPS attributes be treated equally and valued at the market price benchmark. The PCIA Decision provides no basis to treat unsold RPS attributes differently from other forms of retained RPS attributes, Moreover, CalCCA's approach recognizes the current value of the attributes to the IOU for purposes of both its Power Content Label and the Clean Net Short program, as well as the future value when used for bundled customer compliance.

We address CalCCA's proposals in more detail below.

II. THE COMMISSION SHOULD ONLY DEEM RA VOLUMES "UNSOLD" WITH APPROPRIATE VALUES, IF OFFERED FOR SALE A MEANINGFUL TIME PRIOR TO RA COMPLIANCE DEADLINES

The Co-Leads agree on the following RA benchmarking methodologies, guided by the PCIA Decision:

- ✓ RA "retained" by the IOU for use for its bundled customers should be valued at the RA Adder value. For the purposes of the ERRA forecast, retained RA will be valued at the market price benchmark (MPB) established for the forecast. For the true-up, retained RA will be valued using the "final" MPB.
- ✓ RA volumes that remain "unsold" must receive a "zero or de minimis" value rather than the RA Adder price.[2] This leads to a lower value for the utility's retained portfolio and thus a higher PCIA paid by departing load.

[2] D.18-09-010 at p. 138.

- ✓ RA attribute that is offered for sale and is sold will be recorded to each utilities' respective portfolio balancing account (PABA) at the transacted price.

CalCCA departs from agreement with PG&E, however, in protocols for determining whether RA can be deemed "unsold" for valuation purposes, pending the outcome of Working Group 3,[3] and the value assigned to unsold RA.

PG&E contends that RA is "unsold" if it remains unsold following the utility's sales protocol as identified in their Bundled Procurement Plan (BPP), and this RA should be valued at zero. PG&E's proposal is opaque and does not drive the right incentives. As an initial matter, the utility's sales protocol is confidential. Moreover, it is unclear whether the BPP provides the necessary incentives to require PG&E to timely move excess attribute to market or whether it simply requires the utility generally to operate as a "prudent manager" without guardrails that are critical to encourage sales of excess attributes.

CalCCA seeks to facilitate a robust market for RA, and to incentivize IOUs to offer RA to the market in a manner that maximizes its value. A simple, bright-line interim rule is desirable. As an interim measure pending the resolution of the RA sales process in Working Group 3 or other Commission Direction, the amount of "unsold" RA should be calculated as that amount of RA that is offered by an IOU not later than the end of August preceding the compliance deadline. If the above requirements are met, the unsold RA should be valued at the floor price of the relevant solicitation, or if there is no floor price, be valued at zero in the calculation of the final benchmark for true-up purposes. If the RA was not offered by the end of August, that volume should be valued at the RA benchmark.

[3] Working Group 3 will determine both the definition of "excess" RA and the timeline for utility solicitations to sell their excess RA.

This timing requirement ensures that the value of RA assets is maximized. Under this revised proposal, RA will either be used or retained by the IOU for compliance, or it will be offered to market participants in time to meet those participants' own compliance requirements. As such, this requirement will ensure that bids in response to solicitations will garner appropriate sale prices and maximize value for the portfolio. The offer requirement is also intended to address instances in which RA has been withheld from the market, and/or offered so late in the year as to attract few, if any, bids. It is simple to administer, and should avoid disputes over what amounts are eligible for privileged, "unsold" treatment in the PCIA. Accordingly, we urge its adoption by the Commission.

As to value, CalCCA proposes that if the IOU restricts sales based on a price floor, the unsold RA attributes that remain should be valued at the price floor. The use of a price floor implicitly acknowledges a value for the attribute. If, however, the IOU does not employ a price floor in its solicitation, the attribute may be valued at zero.

III. ALL RPS ATTRIBUTES RETAINED BY THE UTILITY SHOULD BE VALUED AT THE RPS MARKET PRICE BENCHMARK.

The Co-Leads agree that RPS attribute that is not offered for sale should be valued at the then-current MPB. Likewise, the Co-Leads agree that RPS attributes that are sold should be recorded to the utilities' PABA at the transacted price. The Co-Leads disagree, however, on whether "unsold" RPS should be treated differently from other retained RPS attributes.

PG&E's proposes to value "unsold" RPS attributes at zero. PG&E further proposes that, if previously unsold RPS is later sold, the revenues will be accounted for in the PABA at the transacted price. Finally, PG&E proposes that RPS attributes retained but used for compliance in a future year will be valued at the then-applicable RPS benchmark. Under PG&E's proposal, the lag between REC creation and PABA credit (if any) will be long, and uncertain. In the meantime, such "unsold" RPS receives no value for PCIA purposes, inflating the PCIA.

As an initial matter, nothing in the PCIA Decision directs this treatment of unsold RPS attributes. While the decision spoke expressly to the question of unsold RA, it did not equally address or even mention unsold RPS.

In addition, the reality is that "unsold" RPS has value from the moment of generation. Under existing rules, the IOU takes credit for the RPS attributes in the Power Content Label in the year generated, not in some future year. Similarly, RPS attributes provide value under the Clean Net Short proposal in the year of generation. Finally, unsold and retained RPS can be used for bundled customers' compliance obligations in later years. PG&E's proposal imposes on all PCIA customers the carrying cost for assets that benefit only the IOU and its bundled customers.

CalCCA proposes to treat equally all retained RPS attributes – regardless of the reason they are retained. All retained RPS attributes must be valued at the RPS market price benchmark. This approach recognizes the value of these attributes and is administratively simpler to implement than what PG&E has proposed.

IV. CALCCA NO LONGER REQUIRES THAT CPM CHARGES BE FACTORED INTO THE CALCULATION OF THE RA ADDER.

In the Draft Proposal CalCCA advocated for the inclusion of Capacity Procurement Mechanism (CPM) costs assessed to LSEs into the calculation of the RA Adder. CalCCA proposed that as a cost for procuring RA, such costs should appropriately be included in the RA Adder, and thus, the MPB. After further consultation with PG&E and consideration of the comments received on this subject, CalCCA has decided not to put forward this proposal in the final proposal. CalCCA notes that its concerns are satisfied given that the revenue generated from CPM sales will still be included in the calculation of the MPB. The Draft Proposal will be revised to reflect the Co-Leads' concurrence on this issue.

V. CONCLUSION

The Commission should find as follows:

1. Pending a decision on Working Group 3 issues, RA volumes may be deemed "unsold" only if those volumes are offered for sale not later than the end of August preceding the compliance deadline. Volumes deemed "unsold" should be valued at the floor price where the utility has employed a price floor in its solicitation or, otherwise, zero. This approach will facilitate a robust market for RA assets and incentivize IOUs to offer RA to the market in a manner that maximizes its value.
2. All retained RPS should be treated equally, regardless of the reason for retention, including any "unsold" RPS. This approach recognizes the value of all retained RPS attributes in the Power Content Label, the Clean Net Short and for future compliance use. It avoids disputes over the adequacy of IOU sales efforts, which is currently under consideration in Working Group 3 it is administratively simple to implement.

Respectfully submitted,

Evelyn Kahl

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Association

Dated: May 29, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment U 39 E	Rulemaking 17-06-026 (filed June 29, 2017)

JOINT INFORMAL COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) ON THE PHASE 2 WORKING GROUP #1, END-TO-END BENCHMARK AND TRUE-UP PROPOSAL

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Dated: May 29, 2019

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Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Joint IOUs) provide the following informal comments to the Draft End-to-End Benchmark and True-Up Proposal presented by the Power Charge Indifference Adjustment (PCIA) Phase 2, Working Group One Co-Leads (the "Proposal").[1] PG&E and the California Community Choice Association ("CalCCA"), Co-Leads to the Working Group, presented a Proposal that comprehensively addresses detailed processes required to forecast and true-up PCIA-benchmarks, including the brown power component, the resource adequacy (RA) adder, and the renewables portfolio standard (RPS) adder. The Proposal identifies four (4) areas of disagreement between the Co-Leads, generally concerning the true-up of unsold RA and RPS products, and whether backstop procurement should be considered in the calculation of the RA adder. Where areas of disagreement between the Co-Leads arose, PG&E and CalCCA each presented an alternative in the Proposal for consideration and comment. Overall, the Joint IOUs are supportive of the Proposal and its informal comments are limited to those four issues of disagreement identified by Co-Leads.

[1] Pursuant to Rule 1.8(d), counsel for SCE and counsel for SDG&E has authorized counsel for PG&E to submit these informal comments on behalf of their respective organizations.

I. GENERAL PRINCIPLES

The Joint IOU view and analysis of the alternatives presented by the Co-Leads is rooted in two fundamental principles:

(1) **The Final Commission Decision Must Adopt a Methodology that Complies with the Statutory Prohibition on Cost-Shifting**:

The Public Utilities Code explicitly prohibits cost shifting or cost increases to remaining bundled service customers as a result of departing or migrating load, and, correspondingly, requires that departing load customers not pay costs that were not incurred on their behalf;[2]

(2) **The Final Commission Decision Should Adopt a Methodology that does not Incent the IOUs to Unnecessarily Incur Uneconomic Costs:** IOUs are obligated to comply with Standard of Conduct ("SOC") 4, which requires that "utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[3]

As further described in Section II, the Joint IOUs cannot support results that conflict with one or both of these requirements. Certain of CalCCA's proposed alternatives, such as CalCCA's position on unsold RA and RPS products, would shift costs to remaining bundled service customers. Other CalCCA proposed alternatives would increase total portfolio costs for bundled service and departed load customers alike by incenting uneconomic sales activity in conflict with SOC 4 and Commission direction that Phase 2 of this Rulemaking remain true to the guiding principles of the PCIA Rulemaking's Phase 1 Final Decision (D.18-10-019). A key

[2] *See, e.g.*, Cal. Pub. Util. Code ("P.U. Code") §366.2(a)(4) ("The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."); §366.2(d)(1) ("It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers."); §365.2 ("The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.").

[3] Decision ("D.") 02-10-062 at p. 52.

guiding principle from Phase 1 is for the PCIA "to only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market cost."[4] D.18-10-019 also recognized IOU obligations to adhere to SOC 4 and stated that "utilities are of course required to manage their portfolios prudently."[5] The Joint IOUs cannot support CalCCA proposals that would require it to choose between shifting costs to bundled service customers or to increase costs for all customers or otherwise imprudently manage the PCIA-eligible portfolio.

II. PROPOSAL ALTERNATIVES

The Joint IOUs present the following comments on the Proposal alternatives.

A. RA Offered for Sale Consistent with an IOU's BPP and That Remains Unsold Should be Valued at Zero.

On page 4 of the Proposal, the Co-Leads identify disagreement with the valuation of unsold RA, and the definition of such unsold RA product. The Joint IOU position is that RA offered for sale consistent with an IOU's BPP, and which is not purchased (*i.e.*, it remains unsold), should be valued at zero for the purposes of the true-up.[6] CalCCA presents an alternative to "impute[] a value for such unsold RA equal to an IOU's price floor, if there is one, or zero (if no floor) for amounts that are offered for sale in the first annual solicitation. Otherwise, unsold amounts are treated as retained and valued with at the MBP." [7] CalCCA's alternative is similarly articulated on page 6 of the Proposal, stating that "in the true-up, the price assigned to a de minimis price equal to the IOUs' floor price, and imputed revenue should be allocated pro rata."

As described below, PG&E's alternative should be adopted because it prevents cost shifts and incents portfolio management in a manner consistent with Commission

[4] D.18-10-019 at p. 15 (establishing Final Guiding Principle 1 (h)); *see also id.* at pp. 111-112 (reminding parties that for Phase 2, "any proposals should be consistent with the guiding principles in this decision" and recognizing IOU requirements to adhere to SOC 4.)
[5] D.18-10-019 at p. 112.
[6] Proposal at p. 4.
[7] *Id.*

directives and SOC 4. CalCCA's alternative should be rejected because it would (1) result in cost shifts to bundled customers if an IOU prudently manages its portfolio by applying a price floor to RA sales[8] and volumes remain unsold because bundled service customers would receive no revenue associated with those products but would still need to credit departing load customers for their "value;" or, alternatively (2) require the IOUs to unreasonably manage their portfolios to not implement prudent RA sales price floors, thereby increasing all customer costs. These options are inconsistent with statutory prohibitions against cost-shifting, Phase 2 guiding principles, and SOC 4.

1. Use of a price floor maximizes the value of the portfolio and is consistent with CPUC procurement standards

CalCCA's proposal would provide a disincentive for the use of a price floor in an IOU solicitation. If a price floor is used and RA remains unsold, CalCCA's alternative would require IOU bundled customers to credit departed load customers for that RA at the price floor. CalCCA's proposal should be rejected because it plainly shifts costs to bundled customers by requiring the bundled portfolio to "buy" RA the portfolio does not need.

Price floors in RA solicitations are a prudent portfolio management tool consistent with SOC 4. A price floor minimizes the cost of the PCIA portfolio by ensuring that revenue from an RA transaction is equal to or are higher than the cost of transacting the RA. A simple example in Table 1 below illustrates the effect of selling a contract below the cost of the sale: such a sale will result in higher total net costs for the PCIA-eligible resource. Consider if an unsold resource has a contract cost of $10 ; if the capacity is supplied to the California Independent System Operator (CAISO) as RA then

[8] IOUs have the discretion to establish a price floor in solicitations.

it becomes subject to the CAISO's non-availability standards (currently known as Resource Adequacy Incentive Mechanism (RAAIM) charges). For the purposes of this example, assume the unit has an expected RAAIM charge of $2 and that there are no other incremental costs to consummating the transaction. If the unit is then sold for $1, because no price floor was used, such a sale would result in an increase in total costs of $1.

Table 1: Impact of Selling Below Transaction Cost			
		No Sale	Sale
A	RA Contract Cost ($)	10	10
B	RA Sale Revenue ($)	-	1
C	Expected Cost if Sold (RAAIM Charge) ($)	-	2
D	**Total Cost to Customers ($) (A + B – C)**	**10**	**11**

In this example, all customers paying the PCIA – both bundled service and departing load – will subsidize the entity that purchased RA for $1, and the above market cost of the portfolio increases from $10 to $11. A prudent portfolio manager, on the other hand, should set a price floor of $2.01 in the above example.

Sales that will increase portfolio costs are inconsistent with both basic economic principles as well as with SOC 4 and the Commission's direction that Phase 2 proposals "take all reasonable steps to minimize above market costs." CalCCA's proposal encourages irrational and economically inefficient outcomes, is harmful to both bundled service and departed load customers alike, and should be rejected.

In contrast, PG&E's alternative incents the economic sale of surplus RA capacity in a manner consistent with Commission requirements and processes– in order to value

RA at zero, the RA must be offered as part of a solicitation process consistent with an IOU BPP and remain unsold. The application of a price floor prevents the accumulation of new above-market costs, consistent with the IOU's obligation to prudently manage its portfolio. If offered RA remains unsold because it cannot be economically sold, only then will the trued-up value of the unsold product be zero.

2. Requiring Bundled Customers to "Buy" RA That Does Not Sell Because Bids are Lower than Costs is a Cost Shift.

CalCCA's proposal to value RA offered for sale but not sold at the floor price implies that IOUs decide to keep RA for bundled customer use or "buy" RA when the IOU receives low price offers. That is not the case – to impute such a sale on bundled customers through a true-up mechanism is a cost shift and must be rejected.

When the IOU receives low price offers for RA, it does not consider whether, at such a low price, it might as well retain the RA for bundled customers. Instead, the IOU considers whether the expected revenue is equal to or higher than the expected cost of the transaction, consistent with its requirement to economically dispose of its long position. CalCCA's proposal would price any RA that is offered for sale but is unsold at the price floor regardless of whether having a price floor is the prudent and economically rational thing to do.

A proposal that penalizes bundled service customers for IOU adherence to CPUC requirements to prudently manage its portfolio conflicts with statutory prohibitions against cost shifting. In such case, instead of allocating the above market costs of a PCIA-eligible resource that cannot be resold to all responsible customers, CalCCA's proposal would <u>require</u> bundled customers to purchase the RA, and at a cost that may bear no relationship to the resource's market value. By imputing a value to unsold RA, the departing load customers' PCIA will be lower, and the bundled service customer generation rate will increase to offset the artificially lower PCIA. The Commission should reject proposals that result in such cost shifts.

3. **CalCCA's Alternative is Not Reasonable or Implementable**

In addition to the fact that CalCCA's proposals are inconsistent with statutory requirements and SOC 4, CalCCA's proposal is not well considered. First, it would value RA at the bid floor even in instances where there are no bids at all. This is nonsensical. Second, CalCCA's proposal fails to recognize how bid floors are structured. Bid floors can reflect the variety of different resources within a portfolio and the fact that they have different expected costs. For example, a fossil unit with a low forced outage rate may have minimal expected costs while a hydroelectric unit during a drought might expect relatively higher RAAIM charges. To reflect these differences in expected costs, IOUs may adopt tiered bid floor structures (e.g., 100 MW available above \$2 and 100 additional MW available above \$3). CalCCA's proposal fails to consider tiered bid floor structures because it fails to recognize the purpose of bid floors. Finally, CalCCA's proposal is at odds with prudent sales processes regulated by the Commission, and that have been generally discussed and reviewed by the IOUs procurement review groups and, as applicable, Independent Evaluators.

4. **CalCCA's Alternative is Inconsistent with the PCIA Decision**

Finally, CalCCA's alternative is inconsistent with D.18-10-019 in three ways. The decision states that "A zero or *de minimis* price shall be assigned for capacity expected to remain unsold."[9] First, under the Decision, a potential *de minimis* price only applies to capacity *expected* to remain unsold (i.e., in the forecast phase of PCIA ratemaking), but CalCCA would apply that same price to capacity that *actually* remains unsold (i.e., in the true-up phase of PCIA ratemaking). Second, CalCCA conflates the concepts of a bid floor with a "*de minimis*" price. Because a bid price floor represents expected costs if the product is sold, the floor may be but is not necessarily "trivial" or "minor." Consider the

[9] D. 18-10-019 at Ordering Paragraph 1(c).

example given above: a hydroelectric resource sold at its full RA value (i.e., full net qualifying capacity) during a drought could expect non-trivial RAAIM charges (e.g., hydro output in California during 2015 which was less than a third of output in 2017)[10]. Finally, CalCCA's proposal would dis-incent the application of bid price floors, presenting the real risk of increasing total portfolio costs; this proposal is in clear conflict with the Commission's guiding principle to minimize above-market costs.

B. Quantities of Unsold RA Should Not Be Defined in the First Annual Solicitation

As described above, in the RA true-up calculation, CalCCA's proposed alternative would value RA at "zero (if no floor) [only] for amounts that are offered for sale in the *first annual solicitation* (emphasis added). Otherwise, unsold amounts are treated as retained and valued with at the MBP." [11] The Joint IOUs support PG&E's proposal that RA offered for sale must be done so consistent with commission directives and should not contain a requirement that such volumes must be offered as part of a first annual solicitation. As described below, CalCCA's alternative should be rejected because it would shift costs to bundled service customers based on vague criteria and does not recognize IOU's unique role as Provider of Last Resort ("POLR"). Further, frameworks prescribing the processes for portfolio sales are not in scope of Track 1 of the PCIA Phase 2; these issues pertain to portfolio optimization which are in scope of Track 3.

1. RA Offered for Sale Consistent with CPUC Directives and Approved Processes Should be Considered Offered for Sale and any Associated Unsold RA Should be Considered Unsold.

Each IOU manages its portfolio consistent with its BPP, which is reviewed and approved by the Commission. To the extent that an IOU makes RA available for sale consistent with the rules and processes approved in its BPP, that product should be considered offered for sale and any associated unsold RA should be considered – by definition -- unsold. No IOU should be held to different standards or expected to follow

[10] Table 2. https://www.energy.ca.gov/hydroelectric/
[11] Proposal at p. 4.

different practices in the PCIA calculation methodology than what is adopted in its BPP. As noted previously, changes to the RA sales processes are within scope of Track 3 of the PCIA Phase 2. Changes to these processes should be thoughtfully considered within Track 3 and subsequently incorporated into IOU BPPs, if necessary, rather than accomplished through changes to the PCIA calculation (here, through penalties embedded in rates) that create cost shifts.

CalCCA's proposal would only consider RA quantities that were offered as part of the first annual solicitation as potentially unsold, regardless of whether such a practice to offer such quantities of RA is consistent with an IOUs BPP. Absent that initial offering, remaining bundled service customers would be forced to purchase the excess product at the benchmark by imputing revenues to departing load customers. CalCCA's proposal to require bundled customers to impute RA revenues based on vague criteria shifts costs to bundled service customers. The statutory requirements necessitate its rejection.

2. **CalCCA's Alternative is Unclear.**

CalCCA proposes to tie the amount of RA considered for sale and any associated unsold product to the earliest annual solicitation, but CalCCA does not clarify how the earliest annual solicitation is defined. For example, PG&E held solicitations in the spring of 2018 for multiple years forward, including 2020 and 2021. It is unclear whether a solicitation held multiple years in advance (here, in the spring of 2018 for 2020 and 2021 delivery) would "lock in" offered and unsold RA quantities. Linking unsold quantities to a solicitation held multiple years forward is also unreasonable given the market changes that are currently occurring, including significant load departure and material changes to RA program rules.

3. **CalCCA's Proposal Ignores IOU POLR Obligations and Disincentivizes Early Sales.**

CalCCA's alternative (1) fails to recognize IOU's unique role as a POLR and (2) fails to accomplish the intent articulated by CalCCA at the May 16 working group meeting: to incent IOUs to sell more RA product earlier. This is because the further in advance of the RA compliance deadline that the IOU sells, the more uncertainty there is concerning compliance rules and available volumes.

First, the CalCCA proposal does not allow the IOU to appropriately consider its POLR obligation in determining the quantity of RA it can make available before significant uncertainties have been resolved. Specifically, IOUs have an obligation to serve load and must account for other LSEs that shed load or delay or cancel launch dates, as has been observed previously.

Second, by "locking in" the quantity that is considered offered for sale at the earliest annual solicitation, CalCCA's proposal creates a disincentive to hold early solicitations given uncertainties. For example, an IOU may not know what RA value its wind and solar resources have pending a CPUC study so it cannot accurately assess the amount of RA available for sale. The IOU may be comfortable selling 75% of what it estimates the RA value of those wind and solar resources to be and sell such volumes in an early solicitation. However, CalCCA's proposal would penalize IOUs' bundled service customers for a lack of perfect insight into any uncertainties by requiring the exact excess volume of RA in the portfolio be offered for sale in the earliest solicitation. Under CalCCA's construct, it would be more prudent for the IOU to wait until all the various unknowns (e.g., RA counting rules, final RA allocations, import allocations) are resolved prior to transacting.

C. RPS Products Offered for Sale and Remaining Unsold Should not be Attributed to Bundled Service Customers Unless sold or Used for Compliance.

The Working Group Co-Leads similarly disagree on the application of imputed revenues for unsold RPS products. PG&E's alternative proposes that no revenue be recorded for RPS products offered for sale consistent with an IOU RPS Plan unless such products are actually sold or used by the IOU for compliance purposes.[12] CalCCA's alternative proposes that unsold volumes should be considered to be under consideration in Working Group 3, and that unsold RPS should be valued at the benchmark.[13] The Joint IOUs oppose the CalCCA alternative, as it would require bundled customers to impute revenues to departing load customers for RPS products the IOUs' bundled service customers do not need and the market does not want. Requiring bundled service customers to compensate departing load customers for products lacking any market value shifts costs to bundled service customers, and that result is unlawful. In contrast, PG&E's alternative incents the sale of surplus RPS products by requiring RPS products be offered through solicitations consistent with commission directives (e.g., an approved RPS Plan). If the RPS product is offered for sale, however, revenues should only be credited to departing load customers if, and to the extent to which, bundled service customers actually receive market revenues (or if the product is used by the IOU for bundled service customer compliance purposes).

As noted in previously in regard to RA sales, frameworks prescribing the processes for portfolio sales, including RPS sales, are not in scope of Track 1 of the PCIA Phase 2; these issues pertain to portfolio optimization which are in scope of Track 3.

1. CalCCA's Proposal Effectively Forces Bundled Service Customers to Buy RPS Products They do Not Need, Harming Bundled Service Customers

CalCCA proposes to assign a value to RPS generation offered for sale but which remains unsold. RPS generation that an IOU offers for sale is excess to its customers' needs, would shift costs to bundled service customers by forcing those customers to effectively purchase such excess RPS at the benchmark, and is just as unreasonable and inequitable as CalCCA's proposal for excess RA true-up described above (for the same

[12] Proposal at p. 8.
[13] Proposal at p. 9.

economic principles). It is also plainly unlawful for remaining bundled service customers to subsidize departing load customers through the higher bundled customer generation rates that will mathematically result from CalCCA's proposal.

2. The Value of Unused or Unsold RPS Product is Not Known and Should Not be Imputed to Bundled Service Customers

Unlike RA which literally has no value after the compliance period has passed, it is unknown at this point whether RPS products that remain unsold will have any future value to remaining bundled service customers or to the market. RPS products that are offered for sale and that remain unsold after generation may – but are in no way are guaranteed to -- have value subsequently if they are (a) used to exceed compliance requirements by an IOU, (b) retired to an IOU RPS bank for hypothetical future use if an IOU is short, or (c) sold for a lower value compliance product (i.e., sold as an unbundled renewable energy credit). Unsold RPS products also may very well have no value if they (a) expire or (b) are banked by an LSE that is not able to use them for compliance. Given this uncertainty, the value of the marketed REC that remains unsold cannot be assigned or imputed to the bundled service customer unless and until it is actually sold or is actually used for the benefit of the bundled portfolio.

D. The Capacity Procurement Mechanism (CPM) is not a Market-Based Transaction and Should not be Included in the RA Adder Calculation

The Co-Leads also disagree on whether CPM transactions should be included in the RA Adder calculation. CalCCA proposes CPM be included, and PG&E does not.[14] The Joint IOUs support the PG&E proposal. The Joint IOUs additionally note that CalCCA previously proposed the use of the CPM as a value for excess RA in the PCIA OIR Phase 1[15], and the Commission declined to adopt this proposal.

The CPM is a backstop procurement framework that ensures there is sufficient capacity to meet load requirements from at least 30 days out to 12 months, to address unexpected

[14] Proposal at pp. 13-14.
[15] CalCCA Testimony, Volume 1, p. 2B-9, lines 2 to 5 and CalCCA Opening Brief, page 59.

conditions, and to retain and compensate for 30 days any non-RA capacity issued as part of an Exceptional Dispatch (Federal Energy Regulatory Commission-approved exceptional dispatch provisions). Additionally, for procurement of capacity at risk of retirement the CAISO will also procure for at least 30 days to 12 months out to ensure load is served but may suspend CPM payments if the LSE procures a portion of the CPM capacity in the bilateral markets. Furthermore, the CAISO may procure a specific multi-month commitment from resources in danger of shutting down. In the event there are multiple resources that may satisfy the backstop procurement, preference will be given to non-use-limited resources over use-limited resources and consideration of specific operational characteristics of the resource. Prior to the issuance of a CPM designation, CAISO will post a report on the basis and need for a CPM designation on website.

The California Large Energy Consumers Association ("CLECA") is correct that CPM transactions are inappropriate for inclusion in the RA Adder and runs afoul of D.18-10-019. CLECA correctly ascertained that the Commission clearly rejected the proposal in D.18-10-019 in favor of market-based transactions. More specifically, the Commission directed use of The Utility Reform Network's ("TURN") adder:

> "We adopt TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n). A zero or de minimis price shall be assigned for capacity expected to remain unsold."[16]

TURN explicitly opposed the use of the CPM as the RA Adder. In reference to a question about whether party proposals, including CalCCA's proposal to use the CPM price as a value of surplus capacity, are reasonable, TURN stated the following:

> "No. These parties do not just want the Commission to continue using a measure of RA value that exceeds current market prices in the Market Price Benchmark, they want to increase the hypothetical RA market value even further."[17]

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[16] D.18-10-019 at p. 73.
[17] Ex. TURN-002 in R. 17-06-026, Rebuttal Testimony of Kevin Woodruff, p. 6 lines 19 to 21.

Similarly, in response to CalCCA's proposal to use the CPM to benchmark capacity, CLECA's testimony in Phase 1 explained why the CPM price is not appropriate for use in the RA Adder or for benchmarking capacity costs:

> Reliability Must Run and CPM contracts are used for backstop when resources that are not contracted for RA are determined through power flow studies to be needed for reliability. Market prices for capacity have been dampened by the existence of excess capacity procured for policy reasons other than capacity value, such as RPS procurement.[18]

D.18-10-019 is clear that the RA Adder is to be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions;" and this direction does not include use of CAISO backstop procurement.

III. CONCLUSION

The Joint IOUs respectfully request that these informal comments inform the Commission's consideration of the Proposal.

Respectfully Submitted,

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[18] Ex. CLECA-1 in R. 17-06-026, Testimony of Dr. Barbara R. Barkovich, at p. 12.

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THE PUBLIC ADVOCATES OFFICE'S INFORMAL COMMENTS

ON THE ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDERING ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT (R.17-06-026)

PHASE 2, WORKING GROUP ONE: BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

R.17-06-026
May 29, 2019

Submitted by	**Organization**	**Date Submitted**
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The Public Advocates Office submits the following informal comments in response to the May 16, 2019 Final Workshop for Working Group One: Benchmark True-Up and other Benchmarking Issues.

Scoping Memo Issue #4: Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark?

Number of RPS and System/Flex RA Adders

The slide deck used in the May 16, 2019 final PCIA Working Group 1 workshop states that the Public Advocates Office "[s]upports single adders for RPS and System/Flex RA."[1] In its informal comments filed on April 2, 2019,[2] the Public Advocates Office expressed its support for aggregating local resource adequacy (RA) adder data at the transmission access charge (TAC) area level, for including fixed-price renewable portfolio standard (RPS) contracts in the RPS market price benchmark, setting the unsold RA de minimis price at the RA price floor, and its opposition to including capacity procurement mechanism (CPM) backstop procurement in the RA adder calculation.[3]

However, at no point did the Public Advocates Office indicate support for a single adder for the RPS and System/Flex RA benchmark. In fact, the Public Advocates Office does not support a single adder being used for both System and Flex RA combined. The working group co-leads, PG&E and CalCCA, did not suggest a single adder in their "Draft End to End Benchmark and True-up Proposal" (draft proposal) circulated on May 20, 2019.[4] The Public Advocates Office supports PG&E and CalCCA's position on the RA and RPS adders as stated in the draft proposal.

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[1] PCIA Phase 2: Working Group One, Benchmark True-Up and Other Benchmarking Issues, Working Group Meeting #3 on Scoping Memo Issues 1-7, May 16, 2019, slide 13.

[2] The Public Advocates Office did not submit any other comments for PCIA Phase 2, Working Group One aside from the April 2, 2019 comments.

[3] The Public Advocates Office's Comments on PCIA Phase 2 Working Group 1, April 2, 2019.

[4] "There is a single Flexible RA Adder used by all three IOUs, calculated using transacted flexible RA not used for local purposes. There is a single System RA Adder used by all three IOUs, based on transacted RA not used for local or flex purposes." PCIA OIR: Working Group 1, "Draft End to End Benchmark and True-up Proposal," p. 3.

Aggregating Local RA

In its informal comments submitted on April 2, 2019, the Public Advocates Office responded in support of aggregating the local RA adder using RA sales and purchases by local area rather than by TAC areas to provide more granular information. However, the Public Advocates Office has changed its position on this topic and now supports the proposal to aggregate the local RA adder using RA sales and purchases by TAC area to preserve confidentiality and avoid market power issues.

Energy Division staff calculates reported purchase and sale prices from a five-year period when determining capacity prices by local area. In the PCIA proceeding, as specified in Ordering Paragraph 1c. of D.18-10-019, "(t)he RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and Electric Service Provider (ESP) transactions made during (year n-1) for deliveries in (year n)." This means that the RA adder for the PCIA will be calculated based on data from only one year (n-1) rather than the five years upon which Energy Division bases its calculation. Therefore, in the case of the PCIA RA adder calculation, local area data may be too granular, particularly in areas where there are few market participants. In order to preserve confidentiality and avoid market power issues, the Public Advocates Office agrees that for aggregating local RA prices, it is more appropriate to aggregate RA sales and purchases by TAC area.

The Utility Reform Network (TURN) Proposal for Incorporating Fixed-Price Renewable Energy Transactions into the MPB Analysis

The Public Advocates Office supports TURN's revised May 21, 2019 proposal for incorporating fixed-price bundled renewable energy transactions into the Market Price Benchmark (MPB) analysis. If fixed-price power purchase agreements (PPAs) cannot be included in the RPS MPB this year due to administrative complexities,[5] the Public Advocates Office recommends that the Commission adopt TURN's updated proposal to establish a "requirement that all LSEs also be required to provide the Energy Division (ED) with

[5] Including fixed-priced PPAs is challenging and time-consuming because of the complexity of the calculations, the difference in units between index-plus and fixed-price contracts, and the significant lag between execution and online date results in stale prices.

information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past 3 years (n-3, n-2 and n-1) for delivery in the following three years (n, n+1, n+2)." This information will provide Energy Division with insight into whether the co-leads' proposed index-plus approach to the RPS MPB is reflective of the market for fixed-price contracts over time.

Scoping Memo Issue 7: "D.18-10-019 specified that 'a zero or de minimis price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB.' Are further parameters needed to define a de minimis price, and if so, what are these parameters?"

Previously, the Public Advocates Office stated its support for CalCCA's proposal to set the de minimis price for unsold RA at the RA floor price.[6] However, the Public Advocates Office has reconsidered its position and now supports using the zero dollar de minimis value. While neither the RA floor price nor the zero dollar de minimis value fully encapsulate the value of unsold RA, the zero dollar de minimis value is the most appropriate. CalCCA is correct that the RA that the IOUs do not sell below the price floor does have a value but assigning the floor price to the RA adder sends the wrong market signals and could potentially require both bundled service customers and departing load customers to bear additional penalty costs.

PG&E has stated that it does not sell RA below the floor price because the possible California Independent System Operator (CAISO) penalties for doing so could require the IOUs to recover costs in excess of the floor price from both bundled service and departing load customers. If the Commission were to assign the RA floor price value to unsold RA, this would imply that it is *preferable* for IOUs to sell their RA below the floor price and incur the penalties. The Commission must protect customers from paying unjust and unreasonable rates, and selling RA below the floor price for a fee is not the most economically optimal choice. Therefore, the Public Advocates Office supports PG&E's proposal to set the de minimis price at zero dollars.

Consistent with PG&E's position in the draft proposal, the Commission should require the IOUs to identify the quantity of RA offered for sale to an Independent Evaluator (IE) and its Procurement Review Group (PRG) in advance of when bids are due. The IOUs should also document the quantity of RA offered for sale in the Quarterly Compliance Report (QCR) and

[6] The Public Advocates Office's Comments on PCIA Phase 2 Working Group 1, April 2, 2019, p. 4.

show that it is consistent with the Bundled Procurement Plan (BPP).[7] In addition, the IOUs should demonstrate to the PRG that the RA floor price is set at a specific level in order to account for possible CAISO penalties.

[7] Assembly Bill (AB) 57, approved September 24, 2002.

EXHIBIT C

TURN proposal for incorporating fixed-price bundled renewable energy transactions into the Market Price Benchmark (MPB) analysis

May 21, 2019

At the Working Group #1 (WG#1) workshops, TURN repeatedly expressed concerns that the "Brown Power + REC" (BP+REC) model for estimating the market price of renewable energy improperly excludes RPS-eligible bundled and fixed price contracts. Given the heavy reliance on long-term fixed price agreements for newly built resources, and the statutory requirement that 65% of all RPS compliance be sourced under long-term agreements beginning in 2021, the categorical exclusion of fixed-price transactions from the MPB would be extremely problematic. TURN believes that the failure to consider these transactions could skew the MPB and result in renewable adders that materially diverge from the imputed renewable premiums reflected in a large volume of actual market transactions.

In a presentation and comments, TURN outlined a method for estimating the imputed REC value for bundled and fixed price contracts.[1] Although the WG#1 co-chairs have raised issues with the implementation of TURN's method, no party has adequately addressed the concern that exclusive reliance on BP+REC transactions may yield invalid estimates of market prices for renewable energy given the significant volumes of fixed price bundled contracts likely to be transacted in the coming years. In particular, the BP+REC model cannot be expected to estimate the prices paid by Load-Serving Entities (LSEs) for newly developed resources or other fixed price agreements used to meet the 65% long-term RPS contracting requirement.

Given the need for prompt action on the development of a methodology that can be implemented this year, TURN is willing to accept the BP+REC price approach subject to the requirement that all LSEs also be required to provide the Energy Division (ED) with information on all fixed-price transactions (sales and purchases) for renewable energy executed in the past 3 years (*n-3, n-2 and n-1*) for delivery in the following three years (*n, n+1, n+2*).

TURN's proposed timing covers a far longer period of time than proposed by the WG co-leads. The WG co-leads proposed limiting reporting to transactions executed in *n-1* for delivery in the first three quarters of year *n*. The extended timeline is intended to ensure the inclusion of data from fixed-price bundled transactions for new generation

[1] See "Second Progress Report…" of April 22, Appendix B. See also TURN's informal comments served March 8.

that typically involve multi-year delays between the contract execution date and the date of initial commercial operation. Absent an extended timeline for reporting fixed price transactions, the data available to ED would be limited almost exclusively to purchases and sales from existing resources with no information relating to the pricing of newly developed resources. A six-year timeline will ensure that all fixed-price contracts for new projects are included in the reporting obligation.

Data for each fixed-price bundled transaction should include price, contract duration, delivery node, hourly delivery profile and Resource Adequacy value.[2] This data should be compiled by ED and aggregated information should be publicly released if there are sufficient data points to protect confidentiality. If there are insufficient data points, then confidential information should be retained by ED but made available to the Public Advocates Office and non-market participants pursuant to a non-disclosure agreement.

Although TURN is not proposing a methodology for incorporating data from fixed-price bundled contracts into the MPB at this time, the pricing information should be used to provide an ongoing assessment as to the reasonableness of the BP+REC approach. The assessment should include additional efforts to develop a method of calculating an imputed REC value for fixed-price contracts. While TURN recognizes the challenge of comparing the market price for energy and RA from renewable generation with different technologies and locations, the collection and analysis of transaction data may allow ED to develop valid, robust and easily-calculated values. If such an approach can be developed over time, and the imputed REC price for fixed-price bundled transactions diverges from the REC prices reported under the BP+REC approach, the Commission should incorporate the analysis of fixed-price bundled transactions into the MPB calculation.[3] This change could be proposed by ED or any other party and adopted pursuant to a Resolution.

TURN also recommends the Commission set an explicit sunset date for using the BP+REC pricing model at which time one or more models for estimating the market prices of RPS-eligible energy contracts could be considered (including re-adopting the BP+REC model for some portion of RPS-eligible energy).

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[2] TURN notes that the initial presentation materials for Working Group #3 (WG#3) proposed that the IOUs be directed to sell excess RPS on differing mid- and long-term durations, including the 10-year RPS contracting requirement, as well as different pricing terms ("Index + (attribute" or "Fixed price") and other resource attributes. See "Working Group #3…Working Session #1" presentation of April 29, slides 14-15.

[3] Such imputed REC values could be either higher or lower than the short-term REC prices in future markets, depending on future power market prices and renewable development costs.

EXHIBIT D

PCIA Phase 2: Working Group One

Benchmark True-Up and Other Benchmarking Issues

Working Group Meeting #3 on Scoping Memo Issues 1-7

May 16, 2019

Safety – Roles and Responsibilities

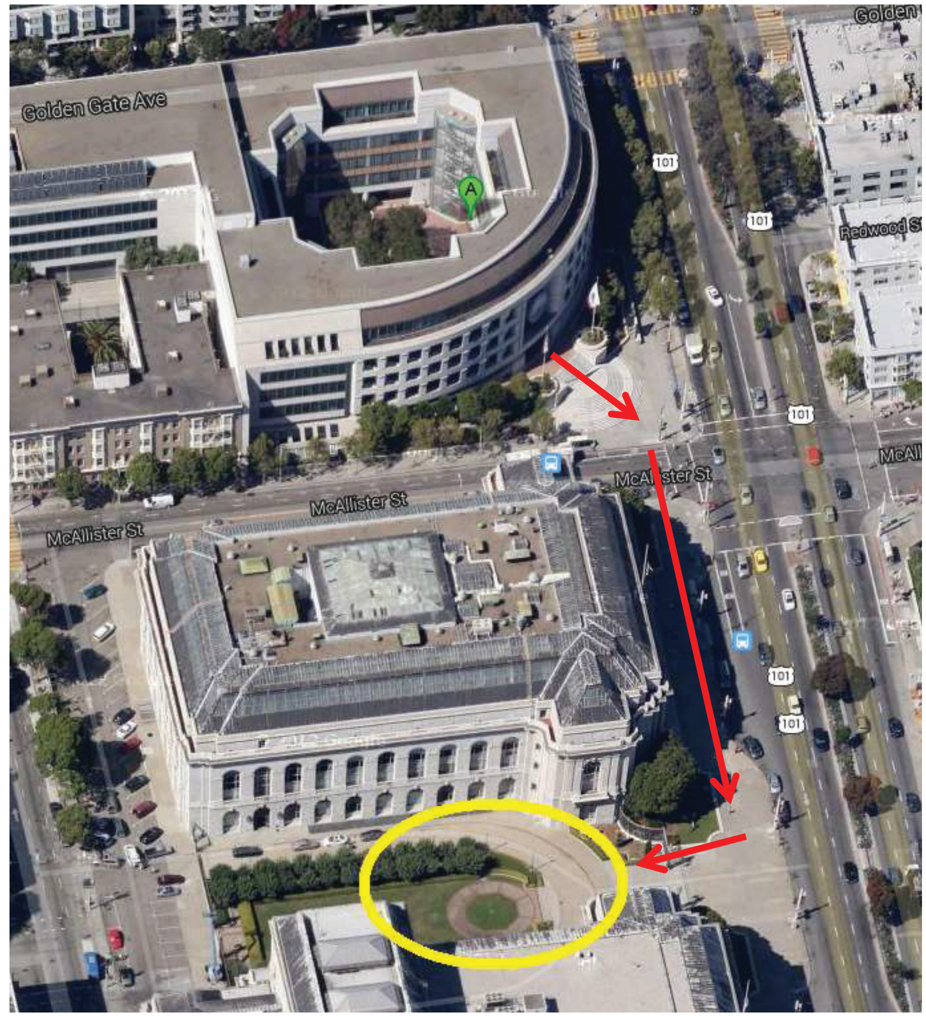
Call 911	CPR AED First Aid	Meet & Greet Safety Personnel	Duck Cover & Hold	Sweep the Room	Silence Cell Phones Get OUT Hide OUT Keep OUT Take OUT
Maria Wilson	**Erica Brown (AED)** **Savi Ellis (CPR)**	**Ian Quirk**		**Rhett Kikuyama**	

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Safety - Evacuation Procedure

In the event of an emergency evacuation:

- Cross McAllister Street
- Gather in the Opera House courtyard down Van Ness, across from City Hall.



WIFI Access

Network: CPUCguest

Username: guest

Password: cpuc43019

Introduction

Purpose of Today's Workshop

- Review Stakeholder Feedback on Co-Lead Proposal from 2nd Working Group Meeting (3/26/19)
- Present final Co-Lead proposal on Benchmark and True-Up (Scoping Memo Issues 1-7)
- Highlight open issues for briefing
- Identify next steps

Introduction

Agenda for May 16, 2019

- Procedural Update
- Stakeholder Feedback on New Issues from 3/26/19
- Updated and Final Co-Lead Proposal
  – “End-to-End Calculation”
  – Issues of non-consensus
- Recap and Next Steps

PCIA Phase 2 – Working Group Roadmap

Three Concurrent Working Groups; Co-led by a Utility and CCA/DA Representative

2018	2019	2020

Phase 2: Policy Development

"Procurement Process Reference Guide" (COMPLETE)
- Joint Effort by 3 IOUs (distributed to service list on 4/26/19)

WG #1: Benchmark True-Up (PG&E/CalCCA)
- **Benchmarks and True-Up (Today's Focus)**
- Methodologies to Forecast Departing Load & PCIA on Bundled Customer Bills (1st Workshop 4/29/19)
- Decisions Expected Q4 2019

WG #2: PCIA Prepayment (SDG&E/AReM/DACC)
- Calculation and Approval of PCIA Prepayments
- 2nd Workshop 5/31/19 - Decision Expected Q1 2020

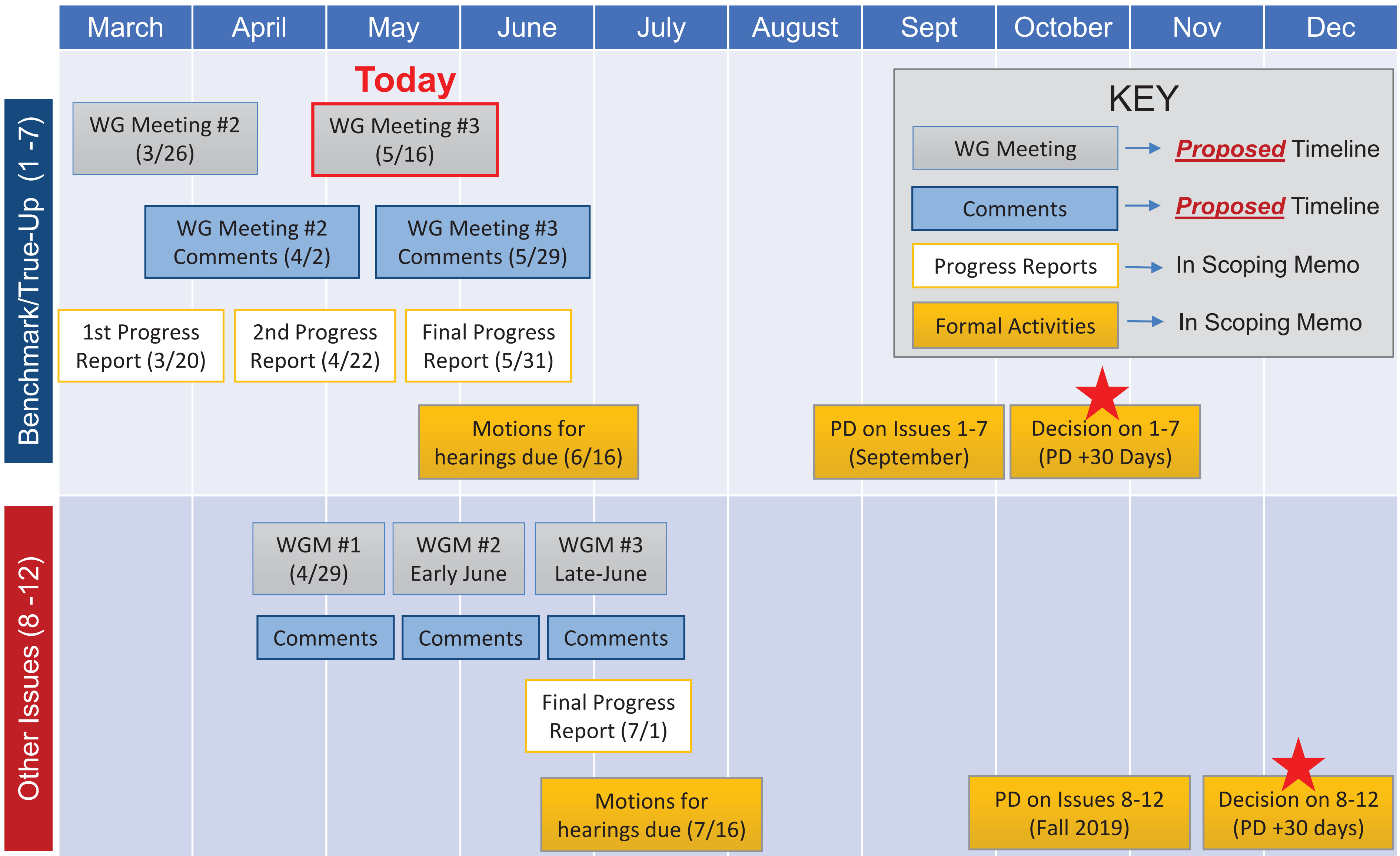
WG #3: Portfolio Optimization (SCE/CalCCA/Commercial Energy)
- Disposition of Long Investor Owned Utilities' Portfolios
- Going-forward Portfolio Management Standards
- 2nd Workshop mid-July - Decision Expected Q2 2020

Working Group 1: Activities to Date

Date	Co-Lead Coordination Activities
1/16	Kickoff Meeting
1/29	Weekly Meeting
2/5	Weekly Meeting
2/12	Weekly Meeting
2/13	Conference Call
2/15	Whiteboarding Session
2/20	Whiteboarding Session
2/26	Weekly Meeting
3/1	**All Party Workshop Issues 1-7 #1**
3/5	Weekly Meeting
3/7	Follow-up Meeting with Energy Division
3/8	**Stakeholders submitted comments on Workshop issues 1-7 #1**
3/11	Conference Call – Touch base on stakeholder comments and workshop outcome
3/12	Weekly Meeting
3/14	Whiteboarding Session
3/19	Weekly Meeting
3/19	Follow-up Meeting with Energy Division
3/20	Whiteboarding Session
3/22	Conference Call – Prepare for Workshop #2
3/26	**All Party Workshop issues 1-7 #2**
4/2	**Stakeholders submitted comments on Workshop issues 1-7 #2**
4/2	Weekly Meeting
4/3	Whiteboarding Session

Date	Co-Lead Coordination Activities
4/3	Whiteboarding Session
4/9	Weekly Meeting
4/10	Whiteboarding Session
4/12	Whiteboarding Session
4/16	Weekly Meeting
4/17	Whiteboarding Session
4/18	Follow-up Meeting with Energy Division
4/18	Whiteboarding Session
4/24	Weekly Meeting
4/26	Whiteboarding Session
4/29	**All Party Workshop Issues 8-12 #1**
4/30	Weekly Meeting
4/30	Conference Call
5/1	Whiteboarding Session
5/3	Conference Call
5/3	Whiteboarding Session
5/6	**Stakeholders submitted comments on Workshop issues 8-12 #1**
5/7	Follow-up with Energy Division
5/8	Whiteboarding Session
5/9	All Party Meet and Confer
5/13	Conference Call
5/14	Weekly Meeting
5/16	**All Party Workshop Issues 1-7 #3**

Proposed 2019 Schedule for Working Group One



Stakeholder Feedback from Workshop #2

6 Parties Submitted Informal Comments on 4/2/19

- AREM/DACC, CLECA, Commercial Energy, CUE, Public Advocates Office, Shell
- <u>Themes Included</u>
  - Timing of Data Responses to Energy Division
  - Number and Types of Market Price Benchmarks
  - Accounting for Multi-Year Local RA in RA adder
  - Local Resources transacted for System RA
  - Valuing Unsold RA in the Forecast and True-Up
  - Contract Extensions and Amendments in the MPB
  - Bundled Contracts in the RPS MPB
  - Inclusion of CPM in RA Adder
  - Confidentiality

Additional Meetings with Energy Division

- 3/7, 3/19, 4/18, 5/7
- Focused on Reporting Templates and Data Request Timing

Responses to Stakeholder Feedback from Working Group Meeting #2:

New Issues from 3/26/19

Timing of Data Responses and Energy Division Benchmark Publication

Stakeholder Comments

- **AReM/DACC**: Opposes quarterly reporting. Strongly prefers annual reporting over quarterly. Improved data templates should facilitate calculation by Energy Division (p. 1).
- **Shell:** Opposes quarterly reporting (p.1).

Response

- Quarterly data responses, at least in the near-term, are necessary to allow Energy Division to timely and accurately calculate the RA and RPS adders.
- Quarterly responses will include incremental data only.
- Once the process is established, data responses could be reduced in frequency to every 6 months, or perhaps annually.
- The decision when/if to reduce data response frequency in the future should be made by Energy Division based on their needs.

Defining Number and Types of MPBs

Stakeholder Comments

- **AReM/DACC**: Supports co-lead proposal (p. 5).
- **Public Advocates:**
  - Supports single adders for RPS and System/Flex RA.
  - Suggests Local RA Adders be differentiated by local area, not TAC Area (p. 1).

Response

- Support proposal from second working group meeting
  - RPS – Statewide Adder
  - System and Flex RA – Statewide Adders
  - Local RA – Adders by TAC Area[1]

1. D. 18-10-019 Specifically describes Local RA adders differentiated by IOU TAC Area (p. 74)

Accounting for Multi-Year Local RA Procurement in the RA Adder

Stakeholder Comments

- **AReM/DACC**: Supports multi-year Local RA proposal, though would possibly require a petition to modify D. 18-10-019, as it would use contracts delivering beyond year n+1 (p. 5).
- **CUE:** Supports proposal by co-leads presented at working group meeting #2 (p. 2)

Response

- **Updated Proposal:**
  - **2020**: Transactions executed in Q4 n-2 and Q1-3 of n-1 for delivery in year n.
  - **2021 and Beyond:** Transactions executed in n-2 for delivery in year n.
- Co-leads have amended proposal to exclude transactions executed in year n-3. Co-leads believe this comports with both the spirit and letter of D.18-10-019 to base the benchmark on recent transactions.

Local Resources Transacted for System RA

Stakeholder Comments

- **CLECA**: Local resources transacted for System RA should not be included in the Local RA MPB (p. 4).
- **CUE:** Supports inclusion of such transactions in calculating the Local RA MPB (p. 3).

Response

- Support proposal from second working group meeting that Local Resources transacted for System RA should ***not*** be counted in the Local RA Benchmark.

Unsold RA in *ERRA Forecast*

Stakeholder Comments

- **CLECA**: Supports strawman proposal given at working group meeting #2 for defining quantity, but suggested 5%-10% of the contract price should be the de minimis value of unsold RA in the forecast (p. 5).
- **CUE:** Supports proposal for forecasting volumes of unsold RA presented at working group meeting #2. Capacity expected to remain unsold should be valued at zero (p. 4)

Unsold RA in *ERRA Forecast*

Response

Quantity

- **Co-Lead Position on *Quantity*:** Volumes should be *forecast* per co-lead proposal to use a volume equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load.

Value

- **PG&E Position on *Value*:**
  - RA quantities forecasted to remain unsold should be valued at zero when calculating the PCIA as part of the ERRA forecast.
- **CalCCA Position on *Value*:**
  - Forecasted unsold RA should be valued at zero as part of the ERRA forecast;
    - Zero value use in forecast is contingent on use of "floor" price in true-up.

Unsold RA in the ***True-Up***

Stakeholder Comments

- **CLECA**: Also supports a 5-10% de minimis value of unsold RA in the true-up, though perhaps it could be a bit lower than the value used in the forecast (p. 6).
- **CUE:** RA that remains unsold should be valued at zero in the true-up provided that the IOUs have attempted to sell the capacity. Working group 3 is the appropriate forum to discuss conditions that must be met for capacity sales (p. 4).
- **Public Advocates:**
  - Unsold RA should be valued at zero except when the IOUs elect not to sell their RA for less than the floor price. Under which cases, the unsold should be valued at the floor price (p. 4).
  - Requested PG&E clarify how it determines the RA “reserve” (p. 4).

Unsold RA in the ***True-Up***

Response

Quantity

- **Long-term definition of Unsold RA *Quantity*:**
  - A durable definition of “unsold” will be established through the sales process being developed by WG #3
- **Interim definition Unsold RA *Quantity* (2019 and possibly 2020):**
  - **CalCCA:** To qualify as “unsold,” RA must have been offered at the earliest annual solicitation, unless otherwise directed by the Commission.
  - **PG&E:** The IOU will identify RA offered to the IE and PRG in advance of when bids are due and will document the quantity offered in the QCR. The quantity offered will be consistent with the BPP, which is reviewed and approved by the CPUC using processes that provide opportunities for stakeholder participation.

Value

- **PG&E Position on *Value*:**
  - RA quantities that remain unsold should be valued at zero in the true-up.
- **CalCCA Position on *Value*:**
  - RA quantities that remain unsold should be valued at a “floor” price, if any, or at zero if no “floor.”

Contract Extensions/Amendments in MPB

Stakeholder Comments

- **CUE**: If the previous years of the contract were used to calculate the MPB, then the contract extension (if exercised) should be included in the MPB. Alternatively, CUE proposes to exclude contracts with extension/option provisions when calculating the MPB (p. 2).

Response

- **Updated Proposal:** Contract amendments and extensions should be excluded from calculation of the RA and RPS adders.

“End-to-End” Benchmark and True-Up Calculation

Co-Lead Proposal by PG&E and CalCCA

Introduction: "End-to-End" Calculation

Clean Slate, Not Incremental from Current State

- The following slides represent the "Clean Slate" proposal by CalCCA and PG&E for calculating and truing-up the Market Price Benchmarks and PCIA Rates
- This presentation does *not track differences* between the clean slate proposal and the current PCIA process

Issues of Non-Consensus

- To the extent possible, this presentation represents the consensus proposal of the co-leads
- However, *some issues of non-consensus remain* at this time

Overview: “End-to-End” Calculation

Forecasting the PCIA

- Each year, the Investor Owned Utilities (IOUs) forecast the indifference amount, per vintage, that is used to set the PCIA rate
- The indifference amount is the total forecasted costs of the PCIA portfolio, +/- any PABA balances from the prior year, minus the portfolio products valued at one of the below options:
  - **Energy**: Brown Power MPB based on Platts forward prices
  - **RA**: *Forecast* RA Adders, actual transacted price, or zero
  - **RPS:** *Forecast* RPS Adder, or actual transacted price

Truing-Up PABA Entries

- At the end of each year, actual sold, retained, and unsold products are recorded to the PABA at the following values:
  - **Energy**: Actual net CAISO Revenues
  - **RA**: *Final* RA Adders, actual transacted price, zero/floor de minimis value[1]
  - **RPS:** *Final* RPS Adder, actual transacted price (or zero value)[2]

1. Co-Leads did not reach consensus on how to quantify and value unsold RA in the True-Up.
2. Co-Leads did not reach consensus on how to quantify and value unsold RPS in the True-Up.

Overview: Market Price Benchmarks

Energy Division Calculation of MPBs

- Energy Division will conduct incremental *quarterly data requests* on transacted RA and RPS products to calculate benchmarks
- The Brown Power MPB will be based on Platts data
- In the future, Energy Division will have the discretion to conduct the data requests *less frequently than quarterly*

Number and Type of MPBs

- The following MPBs will be published by Energy Division each November 1st on both a *Forecast* and *Final* basis
  - **Energy (Brown Power)**[1]**:** Two MPBs, NP15 and SP15
  - **Resource Adequacy:**
    - System RA: One adder for all IOUs
    - Flex RA: One adder for all IOUs
    - Local RA: One adder per IOU TAC Area
  - **RPS:** One adder for all IOUs

1. Brown Power MPB is only published on a Forecast basis, as actual net CAISO revenues are used in the True-Up.

Energy "Brown Power" Value in ***Forecast*** and ***True-Up***

Energy Forecast Price and Quantity

- In the PCIA Forecast, the Brown Power Market Price Benchmark is used to value the forecasted energy production of the PCIA Portfolio
  - Brown Power MPB is based on on-peak and off-peak Platts forward prices for NP15 and SP15
- The Brown Power calculation methodology is unchanged in the Co-Lead proposal from the status quo

Energy Revenue and Quantity in the PABA True-Up

- There is no "Final" version of the Brown Power MPB
  - Rather, actual net CAISO revenues are booked to the relevant PABA sub-account associated with each PCIA vintage
  - Net revenues are inclusive of CPM revenue

RA and RPS Adders – *Forecast* and *Final*

Transaction Types and Datasets Used by ED

	System and Flex RA Adders	Local RA Adder[1]	RPS Adder
Transaction Types Used to Calculate Adders	Sum of monthly weighted averages for relevant IOU, CCA, and ESP market-based RA-only transactions	Same as System/Flex RA	Volume-weighted average of all IOU, CCA and ESP index-plus market-based PCC1 REC transactions[1]
Forecast Adder Dataset	Transactions executed in Q4 of n-2 and Q1-3 of n-1 for delivery in year n.	**2020**: Transactions executed in Q4 n-2 and Q1-3 of n-1 for delivery in year n. **2021 and Beyond:** Transactions executed in n-2 for delivery in year n.	Same as System/Flex RA
Final Adder Dataset	Transactions executed in Q1-4 of n-1 and Q1-3 of n for delivery in year n.	**2020**: Transactions executed in Q1-4 of n-1 for delivery in year n. **2021 and Beyond:** Transactions executed in n-2 for delivery in year n.	Same as System/Flex RA

1. TURN has proposed and several parties have supported the development of an RPS adder that included fixed price PPAs. The Co-Lead proposal does not contemplate such a calculation, but instead relies on market-based Index-Plus PCC1 REC transactions.

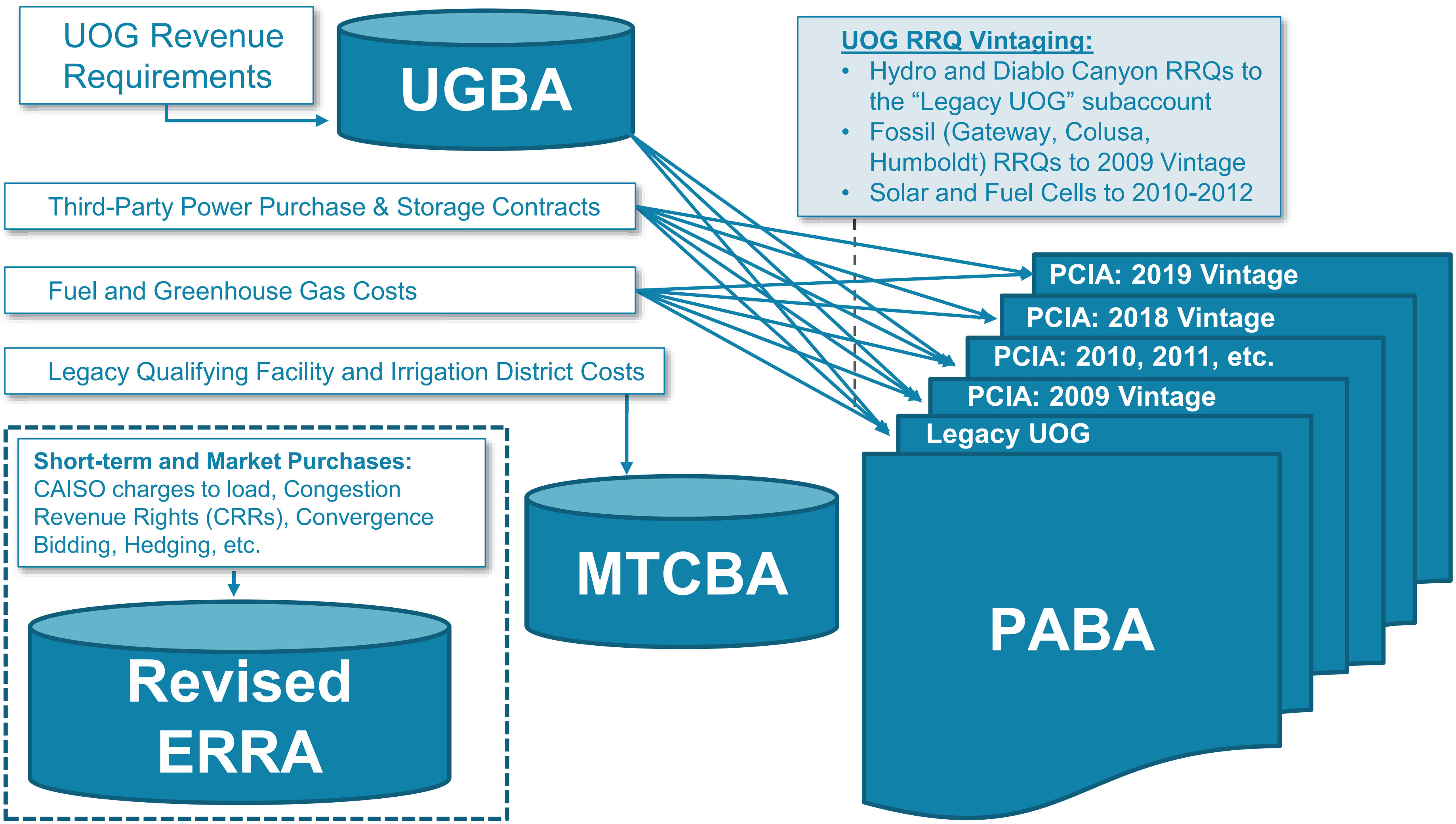
RA Adder – Interactions of Three Products

Cascading Rules for Calculating RA Adders

- There are separate RA Adders for System, Flexible, and Local RA.
- Any transaction for a Local RA product is used to calculate the Local RA Adder (even if the quantity of Local RA product transacted includes flexible capacity product)
- All transactions for flexible RA products that exclude local RA attributes are used to calculate the Flexible RA adder.
- All other transactions are used to calculate the System RA Adder.
- No MW is used to calculate more than one type of RA Adder.

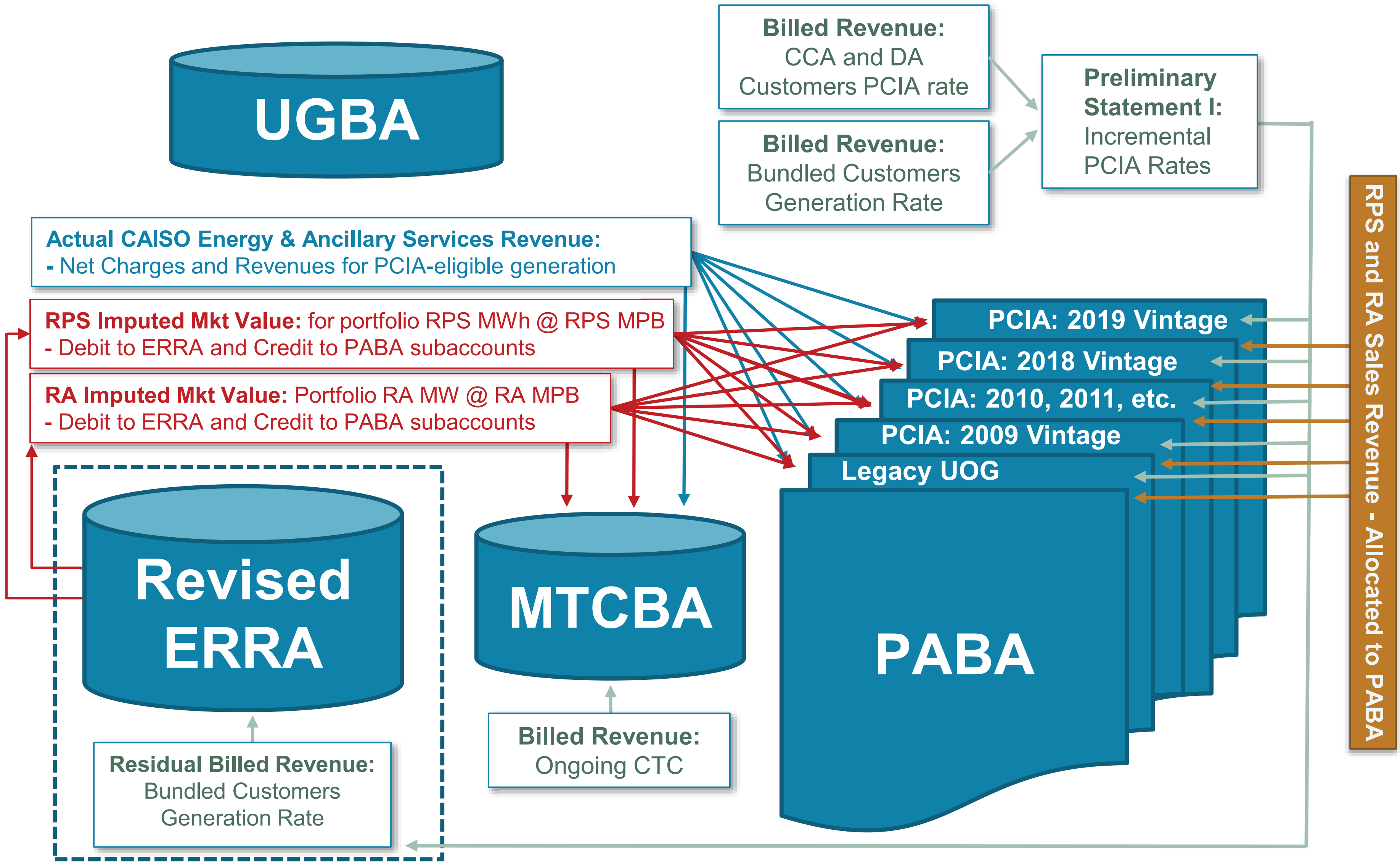
PABA Future State (DEBITS)

UOG RRQ will continue to be booked as UGBA, then transferred to each PABA subaccount



PCIA-eligible contract and fuel costs will be recorded directly to each PABA subaccount

PABA Future State (CREDITS)



Beginning in 2019, ERRA, not UGBA, will receive residual generation revenues

Allocation of Revenue – Direct and Pro Rata

RA and RPS Revenue

- Revenue associated with *sales* or *retained product* will be allocated as follows:

1. **Resource-Specific Sales:**
   - If a single supporting resource is identified at the time of contract execution, revenue will be booked directly to the relevant PCIA subaccount (Legacy UOG, 2009, 2010, etc.)
2. **Non-Resource Specific Sales:**
   - If a single supporting resource is not identified at the time of contract execution, revenue will be allocated *pro rata* to all vintages containing the sold product
3. **IOU Retained Product**
   - Revenue associated with retained product will be allocated across vintages on a pro rata basis
4. **Unsold Product**
   - No revenues, so no values will be recorded or allocated to PABA

Pro Rata Allocation – Illustrative Example

Hypothetical PCIA Portfolio Product Quantities and Pro Rata Allocation Percentages by Vintage

Portfolio Quantities	Units	Leg-UOG	2009	2010	2011	2012	2013	Grand Total
Total RPS Energy	MWh	1,500,000	3,000,000	2,000,000	500,000	100,000	1,000	**7,101,000**
Total System NQC	MW-years	3,000	1,500	400	200	150	100	**5,350**
Total Local NQC	MW-years	1,500	1,000	300	100	75	50	**3,025**
Total Flex NQC	MW-years	1,000	700	100	50	20	10	**1,880**

Pro Rata Allocations	Units	Legacy UOG	2009	2010	2011	2012	2013	Total
RPS Allocations	%	21.12%	42.25%	28.17%	7.04%	1.41%	0.01%	**100.00%**
System RA Allocations	%	56.07%	28.04%	7.48%	3.74%	2.80%	1.87%	**100.00%**
Local RA Allocations	%	49.59%	33.06%	9.92%	3.31%	2.48%	1.65%	**100.00%**
Flex RA Allocations	%	53.19%	37.23%	5.32%	2.66%	1.06%	0.53%	**100.00%**

- To the extent a resource-specific sale is executed by the time of the November ERRA update, product quantity associated with that sale will be removed from vintaged “portfolio quantities” prior to calculating pro rata allocation factors
- Portfolio quantities and resulting pro-rata allocation factors will be based on most recent information available as of the time of November ERRA Update

Value of RA Product

Guiding Principles

- RA product that is not offered for sale is valued at the applicable (forecast/final) benchmark
  - This includes RA that is used for compliance or otherwise retained by the IOU
- RA product that is offered for sale and is sold is valued at the transacted price

Unsold RA

- **PG&E Position:** RA that is offered for sale and is unsold should be valued at zero.
- **CalCCA Position:** RA that is offered for sale and is unsold should be valued at a “floor” price, if any, or at zero if no “floor.”

RA – *Forecast* Quantity and Value

Forecast Values of RA in ERRA Filings

	Retained	Actual Sold	Forecast Sold	Forecast Unsold
Value ($/kW-year)	June: Final RA Adder from previous year November: Forecast RA Adder as calculated by Energy Division	Actual transacted price for any transactions executed up to ~45 days prior to filing date	Applicable RA Adder	$0[3]
Quantity (MW)	June: IOU forecasted RA allocations plus amount retained for IOU use November: Final RA allocations, plus retained amount[1]	Actual transacted volume of RA executed up to ~45 days prior to filing date	Forecasted sold volume	Forecasted unsold volume[2]

1. Amount retained for IOU use includes, but is not limited to, any compliance reserves.
2. The IOU can forecast any volume of unsold RA. If the forecasted volume is equal to the prior year's unsold RA capacity plus or minus a value corresponding to forecasted change in departing load, then the volume will be accepted in the ERRA forecast without further review. Volumes outside of that range may be subject to evaluation in the ERRA forecast proceeding.
3. If price floor is used, consult with PRG and IE. Price floor issue will be discussed in Working Group 3.

RA – *True-Up* Quantity and Value

True-Up Values of RA in PABA

	Retained	Sold	Unsold
Value ($/kW-year)	Final RA Adder as calculated by Energy Division	Actual transacted price	PG&E: $0 CalCCA: Price floor
Quantity (MW)	RA used for compliance from the PCIA portfolio plus amount retained for IOU use[1]	Actual transacted volume	Quantity offered for sale but not sold or used by IOU[2]

1. Amount retained for IOU use is any RA not offered for sale. The total volume of compliance RA may be lower than the total amount of an IOU's RA compliance obligation because the IOU may use non-PCIA-eligible resources to meet its RA requirement (e.g., transactions of less than one year, CAM resources).
2. **PG&E Position:** The IOU will identify RA offered to the IE and PRG, and will document the quantity offered in its QCR. **CalCCA Position:** Pending the outcome of WG#3 to qualify as unsold, RA must have been offered at the earliest annual solicitation, unless otherwise directed by the Commission.

Value of RPS Product – PG&E Proposal

Guiding Principles

- Existing bank (generated in 2018 or before) has been bought and paid for by bundled customers at previous years' RPS adders.

- The following principles apply to RPS generation that has not yet been banked or used for compliance (2019 and beyond).
  - RPS product that is offered for sale and is sold is valued at the transacted price

Differences on Unsold

  - RPS product that is not offered for sale and is used for RPS compliance or otherwise retained by the IOUs is valued at the applicable (forecast/final) year n RPS Adder
  - RPS product that is offered for sale and is unsold at the end of year n is recorded to PABA as no credit until it is:
    1) Used for compliance, if at all, at which point it will be valued at the applicable future year's RPS adder (n+x), or
    2) Sold (including as PCC3), at which point it will be valued at the actual transacted price

Value of RPS Product – CalCCA Proposal

Guiding Principles

- Existing bank (generated in 2018 or before) has been bought and paid for by bundled customers at previous years' RPS adders.

- The following principles apply to RPS generation that has not yet been banked or used for compliance (2019 and beyond).
  - RPS product that is offered for sale and is sold is valued at the transacted price

Differences on Unsold

  - RPS product that is used for RPS compliance or otherwise retained by the IOUs is valued at the applicable (forecast/final) year n RPS Adder[1]

1. Following the conclusion of WG#3, could support valuation of unsold RPS at a value other than the Final RPS Adder.

RPS – *Forecast* Quantity and Value

Forecast Values of RPS in ERRA Filings

	Retained	Actual Sold	Forecasted Sold
Value ($/MWh)	June: Final RPS Adder from previous year November: Forecast RPS Adder	Actual transacted price for any transactions executed up to ~45 days prior to filing date	Applicable RPS Adder
Quantity (MWh)	Forecasted IOU RPS Compliance Need	Actual transacted volume of RECs executed up to ~45 days prior to filing date	Forecasted sold volume

- Co-Leads aligned on treatment of RPS product price and quantity in the ERRA forecast

RPS – *True-Up* Quantity and Value – PG&E Proposal

True-Up Values of RPS in PABA

	Retained	Sold	Unsold
Value ($/MWh)	Final RPS Adder	Actual transacted price	No credit
Quantity (MW)	Volume used for IOU compliance from the PCIA-eligible portfolio[1]	Actual transacted volume	Actual unsold volume[2, 3]

1. Volume used for IOU compliance may include generation within the year by PCIA-eligible resources and any RECs generated in years prior by PCIA-eligible resources. The total retained volume may be lower than the total amount of an IOU's RPS compliance obligation because the IOU may use non-PCIA-eligible resources to meet its requirement (e.g., PCC 3 product, tree mortality) or may use RPS generation in future years.
2. Actual volume of unsold includes volumes offered for sale and any deviations from forecasted RPS generation (i.e., if a renewable resource generated more or less than forecasted in the year-ahead timeframe, that value would be added or subtracted to the unsold volume in the true-up).
3. Does not include unsold volumes that were not offered for sale due to CPUC sale restrictions (e.g., PURPA).

RPS – *True-Up* Quantity and Value – CalCCA Proposal

True-Up Values of RPS in PABA (Interim Approach)

- To be used until CPUC final decision in PCIA WG #3 clarifies definition of “unsold” RPS product
  - Insufficient record at this time to inform parties on existence or treatment of any “unsold” RPS product
  - Zero value inappropriate without further elaboration on portfolio and RPS bank management practices, currently being addressed in WG #3
  - RECs remain in portfolio at benchmark value while WG #3 does its work

	Compliance/otherwise retained (including what PG&E calls “unsold”)[1]	**Sold**
Value ($/MWh)	Final RPS Adder	Actual transacted price
Quantity (MW)	Volume generated from the PCIA-eligible portfolio minus generation sold from the PCIA-eligible portfolio.[1]	Actual transacted volume

1. Following the conclusion of WG #3, could support valuation of unsold RPS at a value other than the Final RPS Adder.

PABA Mechanics and Entries

Monthly Entries During Year

- **Energy:** Net CAISO revenues
- **RA and RPS:**
  - *Sold Product:* Booked at actual settled sales prices
  - *Retained Product:* Booked at applicable <u>*Forecast*</u> Adder
  - *Unsold Product:* No entry ($0 credit in PABA)

Prior Period Adjustments for True-Up

- **Energy:** <u>NO ADJUSTMENT</u> to net CAISO revenues
- **RA and RPS:**
  - *Sold Product:* <u>NO ADJUSTMENT</u> to actual settled sales prices
  - *Retained Product:* Prior period adjustment made to exchange Forecast Adder for the applicable <u>*Final*</u> Adder
  - *Unsold Product:* Possible prior period adjustments for RPS products sold as PCC 3 recorded as unsold in prior months if PG&E proposal adopted

Potential Reopeners

The Below Items May Necessitate Revisiting Elements of the Co-Lead Proposal

- **Material Transactions Executed Q4 of n for Delivery in n**
  - If a significant volume of transactions at anomalous prices occur in Q4 of n for delivery in year n, calculation of the "Final" RA and/or RPS adders may require modification
- **Central Buyer for RA**
  - If a central buyer is established for Local RA, the calculation and use of the Local RA Adder may require modification
- **Insufficient Transaction Volumes / Thinly Traded Markets**
  - Insufficient index-plus PCC1 transactions to calculate robust RPS Adder
  - Insufficient RA-only transactions to calculate one or more of the proposed RA adders (System/Local/Flex)

Elements of Proposal Where Co-leads are Not Aligned

Inclusion of CPM Procurement in RA Adder

Stakeholder Comments

- **CLECA**: Does not support use of CPM in the RA adder (p. 2)
- **CUE:** CPM procurement should not be included in calculation of the RA adder.
- **Public Advocates**: Supports exclusion of the CPM from calculation of the RA adder (p. 2).

Positions to be Briefed

- **PG&E Position:**
  - Support CLECAs position not to include a backstop procurement price as the price for a forward compliance requirement
  - CPM backstop procurement is not “market-based”, as contemplated by D.18-10-019
  - Any actual CPM revenues of PCIA-eligible resources are credited to PABA
- **CalCCA Position:**
  - CPM costs assessed to LSEs are a cost for procuring RA and are appropriately included in the MPB

Unsold RA Quantity and Value for True-Up

Interim Treatment – Prior to WG#3 Decision

- Co-Leads disagree on how unsold RA should be treated in the True-Up prior to the decision(s) rendered as a result of WG #3
  - This is an "interim" problem for the 2019 True-Up and possibly 2020 as well
  - Co leads expect WG #3 to develop parameters around sales efforts needed to qualify RA product as "unsold"

- **PG&E Position in Interim:**
  - **Quantity:** The IOU will identify RA offered to the IE and PRG in advance of when bids are due and will document the quantity offered in the QCR. The quantity offered will be consistent with the BPP, which is reviewed and approved by the CPUC using processes that provide opportunities for stakeholder participation.
  - **Value:** Zero.

- **CalCCA Position in Interim:**
  - **Quantity:** Offered but not purchased during first annual solicitation provided for in the sales plan.
  - **Value:** "Floor" price, or zero if no "floor"

Unsold RPS Quantity and Value for True-Up

Interim Treatment – Prior to WG#3 Decision

- Co-Leads disagree on how unsold RPS should be treated in the True-Up prior to the decision(s) rendered as a result of WG#3

- **PG&E Position in Interim:**
  - **Quantity:** The IOU will identify the RPS offered to the IE and PRG in advance of when bids are due and will document the quantity offered in the Advice Letter seeking approval of transactions resulting from the solicitation. The quantity offered will be consistent with the RPS Plan, which is reviewed and approved by the CPUC using processes that provide opportunities for stakeholder participation.
  - **Value:** Zero

- **CalCCA Position in Interim:**
  - Insufficient information to evaluate PG&E RPS bank and portfolio management practices
  - In the interim, value RPS at MPB unless sold; if sold value at actual price
  - Once WG #3 has established RPS bank and portfolio management framework, address "unsold" in the true-up

Other Stakeholder Issues

Confidentiality

Stakeholder Comments

- **Commercial Energy**: Reiterates proposal that only Energy Division staff directly responsible to calculating RA and RPS adders should have access to data responses and that after calculating the benchmark, data should be destroyed or returned. States that nothing in D. 06-06-066 prevents the CPUC from creating additional confidentiality protocols. Supports briefing on this topic (p. 2 Comments from WG Meeting #2).
- **Shell**: LSEs should not be required to submit RA and RPS price data to the Energy Division. Rather, data should be reported to an index developer such as ICE. This will represent a liquid platform for trading RA and RPS products that will make the market more competitive and open (p.1 Comments from WG Meeting #2).
- **AReM/DACC**: Proposes that only individuals within Energy Division tasked with calculation have access to data; should be destroyed or returned following calculation (p. 4 Comments from WG Meeting #1)
- **CLECA**: Supports destruction of LSE data responses and acknowledges auditing would require resubmission of data (p. 5 Comments from WG Meeting #1)
- **IEPA**: Confidentiality of data must be protected, and benchmarking should not become a method for market participants to seek price discovery. Commission should clarify confidentiality rules (p. 2 Comments from WG Meeting #1)

Confidentiality

Response

- Ruling issued by ALJ Atamturk on March 20 states that data submitted to Energy Division by IOUs, ESPs, and CCAs entitled to confidentiality protections under D. 06-06-066
- Destruction of data after a 3-year period would prevent audit of past calculations

Including Bundled Contracts in RPS MPB

Stakeholder Comments on TURN Proposal

- **AReM/DACC**: Concerned that TURN's straw suggestion does more to illustrate challenges of including long-term contracts than it does to solve those challenges. Highlights timing delay between contract execution and online date and differences in value by technology. Points out that unbundling fixed price contracts would be burdensome for Energy Division, and simplification such as index plus may be appropriate (p. 3-4).
- **CLECA**: TURN's proposal to include fixed-price PPAs in the RPS MPB warrants further development and discussion (p. 5).
- **CUE:** Supports continued work to develop a methodology to include fixed-price PPAs in the RPS MPB. Supports TURN's recommendation that PPAs involving mandatory procurement, such as forest biomass, should be excluded from the MPB (p. 3).
- **Public Advocates:** Supports including fixed-price power purchase agreements in the RPS MPB. TURN's proposal should be further explored, or the Co-Leads should propose an alternate approach (p. 3-4).
- **Shell:** Goes a step further than TURN's proposal, suggesting that "all transactions" that include RA and/or RPS be included, such as a multi-product PPA or Utility Owned Generation (p. 2)

Including Bundled Contracts in RPS MPB

Evaluation Conducted by Co-Leads

- **Process Steps Taken**
  - Co-Leads have had extensive discussions about how to integrate long-term fixed price PPAs into the MPB
    - Conducted numerical analysis on a variety of potential methodologies
  - Co-leads met with TURN on this issue
- **Challenges to Creating an RPS Adder that Includes Bundled RPS Contracts**
  - Teasing out the value of individual components from a long-term fixed price PPA
    - Adjusting single-commodity RA and energy prices before subtracting those prices from the PPA price to get to the RPS Adder
    - Determining the appropriate forward curve and/or past CAISO market results to use as part of the energy pricing exercise
  - Adjusting for technology
  - Adjusting for location
  - Reducing a strip of future cashflows to a single-year value
    - Capturing value/risk inherent in a long-term deal
  - Addressing lag between PPA execution and commercial online date (COD)
    - Many/most new construction takes more than 2 years from contract execution to reach COD, some up to 5 years
  - Would be a very data-intensive exercise when all adjustments are taken into account

Including Bundled Contracts in RPS MPB

Response

Not Needed to Cover Majority of Current RPS Transactions

- IOUs and CCAs have observed that majority of current RPS transactions are PCC 1 index-plus deals

Results May Not be Meaningful

- Requires many administratively-determined assumptions that could lead to unexpected results
  - For example, could result in $0 or negative PCC1 REC prices, despite REC market trading at positive values
- Phase 1 of the PCIA proceeding was in large part undertaken to remedy unintended consequences resulting from complex administratively set benchmark calculations

Does Not Align with Intent of D.18-10-019

- Administratively set calculation is inconsistent with decision emphasis on “market” transactions for benchmark pricing
  - PCC 1 index-plus transactions represent the best current market value of RECs
- Expanding universe to account for construction timelines of 3+ years is inconsistent with decision focus on recent (n-2) deals, and any cut-off is essentially arbitrary

Recap and Next Steps

Comments on End-to-End Proposal Using common Outline Due:

Wednesday, May 29, 2019

Final Report will be Filed May 31, 2019

Q&A and Discussion

Appendix

Detail of Data Templates Proposal:

RA and RPS

Data Templates – Stakeholder Comments

Stakeholder Comments

- **<u>AReM/DACC</u>**:
  - Reiterate recommendation to include contact prices reporting for purchases only (p. 2).
  - For RA, a row should be added for Local RA MW, similar to what is done for System and Flex RA (p. 2).
  - For RPS, staff should clarify that forecasted volumes are what should be used for “actual deliveries” (p. 2).

Data Templates - Coordination with Energy Division

Follow-Up Discussions with Energy Division Staff

- Co-Leads worked with Energy Division staff to develop a feasible process given the initial proposal of a short turnaround time
  - Minimize time for data clean-ups and LSE follow-ups
    - Minimize free-form data entries
    - Establish clear instructions and descriptions for the reporting requirements for LSEs
    - For the transition period, data request will be quarterly[1]. The RA/RPS Adders will continue to be published once per year in early November

Response

- RA: Use the modified data template
- RPS: Develop a stand-alone data template

[1] All based on input from Energy Division; CCAs are still evaluating.

RA Data Template – Final Proposal

Joint Proposal by Working Group One

Data Field:	Data Field Description:
Reporting LSE's Contract ID	Insert the LSE's unique contract identifier
Month	From the drop-down, select the delivery month for which the price quoted is applicable; Please insert an additional row for each month regardless of whether capacity price or capacity MW amount changes between months
Year	From the drop-down, select the year of delivery
CAISO Resource ID	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list
Resource Name	Name of resource; This field will automatically populate if you select a CAISO Resource ID
Buyer	From the drop-down, select the contract buyer identified on the RA confirmation
Seller	From the drop-down, select the contract seller identified on the RA confirmation
System Capacity Under Contract (MW)	The amount of system MW(s) under contract for the associated month and year of the contract
Flexible Capacity Under Contract (MW)	The amount of flexible MW(s) under contract for the associated month and year of the contract; System and flexible capacity are a bundled product; Do not list a MW amount greater than the system MW amount
Price ($/kW-month)	List the price in $/kW-month format for each month and year of a contract even if the price is same for all months of the year; For example, if a contract covers a 3 year period, you will input 36 lines for the contract
Contract Execution Date	List the date the contract has been executed - mm/dd/yyyy
Type of Generation	Select whether the resource is new, existing, or imported generation; A repower will be considered new generation for this application
Local Area	For "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, provide the expected Local Area; This field will automatically populate if you select a CAISO Resource ID on the NQC list
Zone	For "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, provide the expected Zone; This field will automatically populate if you select a CAISO Resource ID on the NQC list
RA Adder	Field is formula based for Commission purposes only
Transaction ID	Field is formula based for Commission purposes only

RPS Data Template – Final Proposal

Joint Proposal by Working Group One

Data Field:	**Data Field Description:**
Contract ID Between Parties	Insert the parties' unique contract identifier
Purchase or Sale by Reporting LSE	From the drop-down, select whether the transaction is a purchase or sale by reporting LSE
Year	From the drop-down, select the year of delivery
CAISO Resource ID	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list
Resource Name	Name of resource; This field will automatically populate if you select a CAISO Resource ID
Buyer	From the drop-down, select contract buyer identified on the RPS confirmation
Seller	From the drop-down, select contract seller identified on the RPS confirmation
PCC Classification	The expected PCC classification under the contract for the associated year of delivery
Volumes (MWh)	List the expected volumes in megawatt hours under contract for the associated year of delivery
Price ($/MWh)	List the price in $/MWh format under contract for the associated year of delivery; For PCC1 REC + Energy (Index), provide the PCC1 REC-only premium price
Contract Execution Date	List the date the contract has been executed - mm/dd/yyyy
Transaction ID	Field is formula based for Commission purposes only

Subject to change based on open issues concerning RPS Adder calculation

EXHIBIT E

Power Charge Indifference Adjustment (R.17-06-026)

Phase 2: Benchmark True-Up and Other Benchmarking Issues

Working Group

Second Progress Report to the California Public Utilities Commission

California Community Choice Association
Pacific Gas and Electric Company
April 22, 2019

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Introduction and Background

Procedural Background

On October 11, 2018 the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-10-019 modifying the Power Charge Indifference Adjustment (PCIA) Methodology. D. 18-10-019 determined that a second phase of the proceeding would be opened to establish a "working group"[1] process to enable parties to further develop proposals for consideration by the Commission. On February 1, 2019 the Commission issued a scoping memo in Rulemaking (R.) 17-06-026 directing the parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission ("Phase 2 Scoping Memo").[2]

The Phase 2 Scoping Memo designated Pacific Gas and Electric Company ("PG&E") and California Community Choice Association ("CalCCA") as Co-Chairs of Working Group One: Benchmark True-Up and Other Benchmarking Issues ("Working Group One"). The Commission anticipates resolving Working Group One issues "in time to be implemented in the Joint Utilities' respective 2020 [Energy Resource Recovery Account ("ERRA")] Forecast Updates in early November 2019" and the Phase 2 Scoping Memo established a procedural schedule to do so, with a proposed decision on brown power, renewable portfolio standard, and resource adequacy true-up issues issued by September 2019. [3] The Phase 2 Scoping Memo also established a procedural schedule requiring Working Group one to address load forecasting, billing determinants, and bill presentation issues for a proposed decision in fall 2019.[4] The Commission intends for a proposed decision to be released on the Working Group One scoping issues one through seven by September 2019 and a second proposed decision released for issues eight through twelve later in Fall 2019.

[1] "Working group" as used here means all active parties participating in Working Group One meetings, which includes PG&E and CalCCA representatives as well as meeting attendees. A list of participants is included in Appendix C.
[2] Phase 2 Scoping Memo and Ruling of Assigned Commissioner (R. 17-06-026) [hereinafter "Phase 2 Scoping Memo"], p. 3.
[3] Phase 2 Scoping Memo, pp. 3 and 7.
[4] Id.

PG&E and CalCCA as co-chairs of Working Group One, led by Mr. Joe Lawlor and Mr. Todd Edmister respectively,[5] are responsible for a number of tasks, described further below, including scheduling and leading meetings, and serving reports to the Commission according to Scoping Memo.[6] The Initial Progress Report of Working Group One was served on parties to the proceeding on March 20, 2019. This Progress Report satisfies PG&E's and CalCCA's requirement to serve a second progress report of Working Group One's activities.[7]

Working Group One Scope

Issues assigned to working group in scoping memo (issues 1-12)

1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true-up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?
3. Should the true-up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true-up process be addressed?
4. Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annual the RA adder and the RPS adder of the Market Price Benchmark?
5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?

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[5] Other CalCCA representatives included Ann Springgate and Evelyn Kahl as attorneys for CalCCA and Sam Kang as CalCCA's consultant. Also included in some working group conversations were representatives from Peninsula Clean Energy, Silicon Valley Clean Energy, SFCleanPower, and Marin Clean Energy.

[6] Phase 2 Scoping Memo, p. 10.

[7] Phase 2 Scoping Memo, p. 7.

6. How should the Commission clarify/define forecasting amounts of unsold RA?
7. D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the [Market Price Benchmark (MPB)]." Are further parameters needed to define a *de minimis* price, and if so, what are these parameters?
8. Which methodologies, probabilistic or scenario-based, should the Commission adopt to forecast departing load?
9. What are the barriers for the IOUs to obtain the information they need to adequately forecast future CCA departing load and mitigate future forecasting inaccuracies, and how can they overcome those barriers?
10. What mechanisms would help minimize future deviations between announced and actual load departure dates, thereby improving the fidelity of departing load forecasts?
11. Should the Commission clarify the definition of billing determinants and their proper usage for calculating the PCIA, and if so, how?
12. Should the Commission require any changes in the presentation of the PCIA in tariffs and on customer bills, and if so, what should those changes be?

Working Group One Responsibilities

As co-chairs of Working Group One, PG&E and CalCCA are responsible for performing the following tasks:

1. Scheduling the Working Group's meetings, along with handling associated logistics;
    a. Pursuant to the Rules of Practice and Procedure 8.1(b)(3), meeting times, locations, and online access information, if applicable, should be noticed to the entire service list.
    b. Service list notification should include language to inform the service list that decisionmakers may be present at the meeting
2. Leading each of the Working Group's meetings; and

3. Ensuring that the final report, or reports, of each Working Group is finalized and subsequently filed and served at the Commission according to the schedule or that working group.[8]

Co-chairs are also responsible for producing two progress reports and two final reports. Working Group participants are directed by the Phase 2 Scoping Memo "to develop more detailed agreements on how they will approach their responsibilities…to ensure that its work proceeds openly and efficiently".[9]

Summary of Co-Chair Activities

Working Group One Second Straw Proposal Development

Following the production of the Initial Progress Report, PG&E and CalCCA continued weekly conference calls to discuss proposal development and scheduled extended in-person meetings as needed to discuss and/or finalize proposals. PG&E and CalCCA representatives met eight times between March 1, 2019 and March 26, 2019 to revise the Initial Proposal related to Issues 1-7. Six sessions were via teleconference and lasted approximately one hour each; two sessions were in-person at PG&E's San Francisco General Office and lasted 2 hours each. Meetings were collaborative in nature with each party bringing forth proposals and concepts vetted by Investor Owned Utility (IOU) and Community Choice Aggregation (CCA) constituents. To ensure incorporation of stakeholder feedback, the IOUs and CCAs met with their constituents separately to discuss proposal revisions.

By the March 26 meeting, PG&E and CalCCA further developed a straw proposal that established methodology, data reporting, and timing necessary to produce RA and RPS adders for the MPB.

[8] Phase 2 Scoping Memo, p. 10.
[9] Id.

Second Working Group One Meeting

Notification of Second Meeting of Working Group One

On March 19, 2019, PG&E notified the R. 17-06-026 service list that the Second Meeting of Working Group One would be held on March 26, 2019. The notification included a web conference option for parties unable to attend in-person. An additional notice was issued to the service list on March 20, 2019 inviting parties who had previously commented to present on their proposals at the meeting. PG&E provided the working group's Second Meeting Materials to the R.17-06-026 service list on March 25, 2019.

Meeting Description

The Second Meeting took place on March 26, 2019 from 10:00 AM to 1:00 PM in the Courtyard Room of the CPUC San Francisco building. Approximately thirty-nine parties attended the meeting in-person. A web conference option was provided for parties attending remotely, resulting in twenty-two additional participants. A list of attendees is attached to this report as Appendix C, along with information on the number of parties that dialed in, and the parties that used the web conference option.

The presentation given at the meeting is attached to this report as Appendix A. Mr. Lawlor of PG&E presented pages 1-5, 14-16, 25-29, and 32-33. Mr. Edmister, representing CalCCA, presented pages 6-13, 17-20, 30-31, and 34-40. Representing PG&E, Mr. Kikuyama presented pages 21-24, Mr. Quirk presented pages 41-50, and Ms. Brown concluded the meeting by presenting pages 51-58.

TURN also presented at the meeting regarding its proposal to include long term fixed-price contracts in the RPS benchmark. TURN's presentation materials are attached as Appendix B.

Parties were notified at the meeting that written comments on the presented proposal would be accepted through April 2, 2019. CalCCA and PG&E requested that the comments be served via the service list so all parties would have the opportunity to stay informed on the proceeding and Working Group One activities.

Second Straw Proposal Presentation

Detail of Second Straw Proposal

As noted above, for the slide deck with the Second Straw Proposal, see Appendix A. The following section describes how the Second Straw Proposal presented at the Second Meeting addresses Issues 1-7 of Working Group One:

1. Issue 1: Which mechanism(s), procedural and/or methodological, should the Commission adopt to true-up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
    a. Energy Division (ED) issues quarterly data requests to all Load Serving Entities (LSEs); LSE's respond with data for use in developing RA and RPS adders.
    b. By November 1 of each year, ED will publish two sets of RA and RPS adders:
        i. Forecast: to be used in setting the PCIA rates for year N
        ii. Final: to be used in truing up the imputed RA/RPS PABA entries for products (i.e., those products used by the IOUs for compliance)
    c. RA adder: includes market-based RA-only sales and purchases from IOU, CCA, and ESP transactions
    d. RPS adder: limited to market-based PCC1 "index-plus" sales and purchases from IOU, CCA, and ESP transactions
    e. IOUs use forecast RA and RPS adders to establish PCIA rates and include in year N ERRA Forecast Update, filed November of year N-1
    f. IOUs true-up balancing account entries for year N
        i. All recorded transactions of RA and RPS, at actual transacted value and quantities; and
        ii. Final imputed RA/REC adders using RA and RPS adders
    g. Any over- or under-collection is recovered in subsequent year's rate
2. Issue 2: Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?

    a. For forecast year 2020 and beyond, Energy Division will issue a quarterly data request to all LSEs. These data requests will capture purchases and sales from Q4 of year N-2 and Q1-3 of year N-1 for delivery in year N. Energy Division staff will then calculate the RA and RPS forecast and final adders for use in ERRA Forecast Proceeding.

3. Issue 3: Should the true-up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true-up process be addressed?
    a. The true-up process should take place as part of the ERRA Forecast proceedings. Any over- or under-collections are rolled into the following year's PCIA rate, which are filed within the ERRA Forecast Update.
4. Issue 4: Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark?
    a. See above.
5. Issue 5: Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?
    a. Much of the data reported by the categories below is already shared with the ED as part of RA and RPS data requests. Minor updates to the existing templates were proposed to capture the appropriate data points for inclusion in the benchmark. Relying upon the existing data response template currently issued by the ED may increase reporting efficiency.
    b. The data necessary to accurately calculate the RA adder is as follows: contract ID between parties, month and year of delivery, resource scheduling ID, resource name, California Independent System Operator ("CAISO") zone for unspecified resources, buyer, seller, system capacity under contract, local capacity under contract, price, contract execution date, type of generation, combined heat and power contract.

    c. The data necessary to accurately calculate the RPS adder is as follows: contract ID, seller name, buyer name, project name, CAISO resource ID, contract execution date, month and year of delivery, volume, contract length, expected PCC classification, contract price (pre-TOD and TOD adjusted).

6. Issue 6: How should the Commission clarify/define forecasting amounts of unsold RA?
    a. Forecasting unsold RA quantities remains an outstanding issue.
7. Issue 7: D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a *de minimis* price, and if so, what are these parameters?
    a. De minimis price determination for unsold RA remains an outstanding issue.

Open Issues

Working Group One Co-Chairs are still discussing the following issues:

Inclusion of Long-term fixed-price PPAs in RPS market price benchmark

Co-Chairs are exploring mechanisms for including long-term fixed-price PPAs in the RPS market price benchmark.

Use of backstop procurement in the RA adder

Co-chairs do not agree on the use of backstop procurement in the RA adder calculation. CalCCA supports including CAISO Capacity Procurement Mechanism (CPM) transactions in the RA adder on the basis that CPM costs are assessed to LSEs as a cost for procuring RA. PG&E does not support the inclusion of CPM transactions on the basis that these are out of market transactions rather than market-based purchases and sales of RA to inform the adder as generally described by D.18-10-019.

Transitional Issues

Working Group One Co-Chairs continue to discuss an implementation timeline for 2019. It is yet to be determined how the true-up for 2019 will be executed. Additionally, a transitional framework will need to be developed in the event that the CPUC decisions are delayed beyond the end of 2019.

Working Group One Co-Chairs are also discussing how to address issues 8-12.

Verbal Comments Offered in Response to the Second Straw Proposal

Several parties offered substantive verbal comments on the Second Straw Proposal for issues 1-7 at the Second Meeting. Themes included publication timeline of the benchmarks, integration of new local RA rules into the benchmark calculation, inclusion of long term fixed-price contracts in the RPS benchmark, how unsold volumes affect PCIA rates, and how price floors are accounted for in the proposal.

Follow-Ups

Post-Meeting Comments

Six parties filed comments in response to the March 26 meeting: Shell Energy, California Large Energy Consumers Association, Alliance for Retail Energy Markets and Direct Access Customer Coalition, Commercial Energy, Public Advocates Office, and Coalition of California Utility Employees. All informally submitted comments are attached to this report as Appendix D.

Themes of comments centered around confidentiality, data reporting template and protocols, requests to develop TURN's proposal to include bundled contracts (long-term PPAs) in the RPS benchmark, inclusion of the Capacity Procurement Mechanism in the RA adder, de minimis valuation of unsold RA, and calculation of the RA adder accounting for system, local and flex attributes.

Post-Meeting Follow-up with Commission Staff

On April 18, 2019, the Co-leads met with Commission Staff to discuss: further changes to the reporting templates for RA and RPS transactions, and how reporting could be implemented in time for November ERRA forecast filings (i.e., the "November update").

Next Steps

Procedure for Issues 1-7

PG&E and CalCCA continue to convene via conference calls on a weekly basis and schedule extended in-person sessions to consider parties' comments and to further develop the proposal addressing issues 1-7. The co-chairs will meet with their respective constituents to ensure parties' viewpoints are documented and reflected in the resultant proposal.

Meetings Scheduled

The next working group meeting focused on issues 1-7, is tentatively planned for May 13, 2019; exact date/time/location to be announced.

Working Group Report on Issues 1 through 7

The Phase 2 Scoping Memo requires the final report on issues 1-7 to be filed and served on May 31, 2019. The co-chairs anticipate that the final report on issues 1-7 will detail the Brown Power, RPS, and RA benchmark and true-up proposal as developed by the co-chairs for review by the CPUC.

CPUC Decision

The CPUC is scheduled to issue a Proposed Decision on issues 1-7 in September 2019 and anticipated voting on said Decision 30 days after issuance.

Procedural Schedule for Issues 8-12

Meetings Scheduled

A meeting on issues 8-12 is scheduled for April 29, 2019 10:00 AM at the Pacific Energy Center. The meeting was noticed on April 19, 2019.

Meetings are planned for April 29, mid-May, and early June, though specific dates for the last two meetings are yet to be determined.

Working Group Report on Issues 8 through 12

The final report on issues 8-12 is required to be filed and served by July 1, 2019.

CPUC Decision

The CPUC is scheduled to issue a Proposed Decision on issues 8-12 in Fall 2019 anticipated voting on said Decision 30 days after issuance.

Appendices

- Appendix A: Second Meeting Presentation
- Appendix B: TURN Presentation
- Appendix C: Initial Meeting attendee list
- Appendix D: Informal Party Comments

PCIA Phase 2: Working Group One

Benchmark True-Up and Other Benchmarking Issues

Workshop #2:
March 26, 2019

Introduction

Purpose of Today's Workshop

- Present updated proposal on Scoping Memo items 1-7
  - Identify and focus discussion on remaining issues of non-consensus
- Set the stage for how Scoping Memo items 8-12 will be addressed in future workshops
  - Gather feedback on proposed schedule

Agenda for March 26, 2019 - PCIA Workshop

Discussion Topics

- Procedural Update
- Updated Proposal
- Responses to Stakeholder Feedback by Theme
- Recap and Next Steps

PCIA Phase 2 – Working Group Roadmap

Three Concurrent Working Groups; Co-led by a Utility and CCA/DA Representative

2018 | **2019** | **2020**

Phase 2:
Policy Development

Create "Procurement Process Reference Guide"
- Joint Effort by 3 IOUs to be completed prior to first WG#2 Workshop

WG #1: Benchmark True-Up (PG&E/CalCCA)
- **Benchmarks and True-Up (Today's Focus)**
- Methodologies to Forecast Departing Load
- PCIA on Bundled Customer Bills
- 2nd Workshop 3/26/19 - Decisions Expected Q4 2019

WG #2: PCIA Prepayment (SDG&E/AReM/DACC)
- Calculation and Approval of PCIA Prepayments
- 1st Workshop 4/4/19 - Decision Expected Q1 2020

WG #3: Portfolio Optimization (SCE/CalCCA/Commercial Energy)
- Disposition of Long Investor Owned Utilities' Portfolios
- Going-forward Portfolio Management Standards
- 1st Workshop 4/29/19 or 4/30/19 - Decision Expected Q2 2020

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Working Group 1: Activities to Date

Date	Co-Lead Coordination Activities
1/16	Kickoff Meeting
1/29	Weekly Meeting
2/5	Weekly Meeting
2/12	Weekly Meeting
2/13	Conference Call
2/15	Whiteboarding Session
2/20	Whiteboarding Session
2/26	Weekly Meeting
3/1	**All Party Workshop #1**
3/5	Weekly Meeting
3/7	Follow-up Meeting with Energy Division
3/8	**Stakeholders submitted comments on Workshop #1**
3/11	Conference Call – Touch base on stakeholder comments and workshop outcome
3/12	Weekly Meeting
3/14	Whiteboarding Session
3/19	Weekly Meeting
3/19	Follow-up Meeting with Energy Division
3/20	Whiteboarding Session
3/22	Conference Call – Prepare for Workshop #2
3/26	**All Party Workshop #2**
4/2	**Stakeholders to submit comments on Workshop #2**

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Stakeholder Feedback from Workshop #1

7 Parties Submitted Informal Comments on 3/8/19

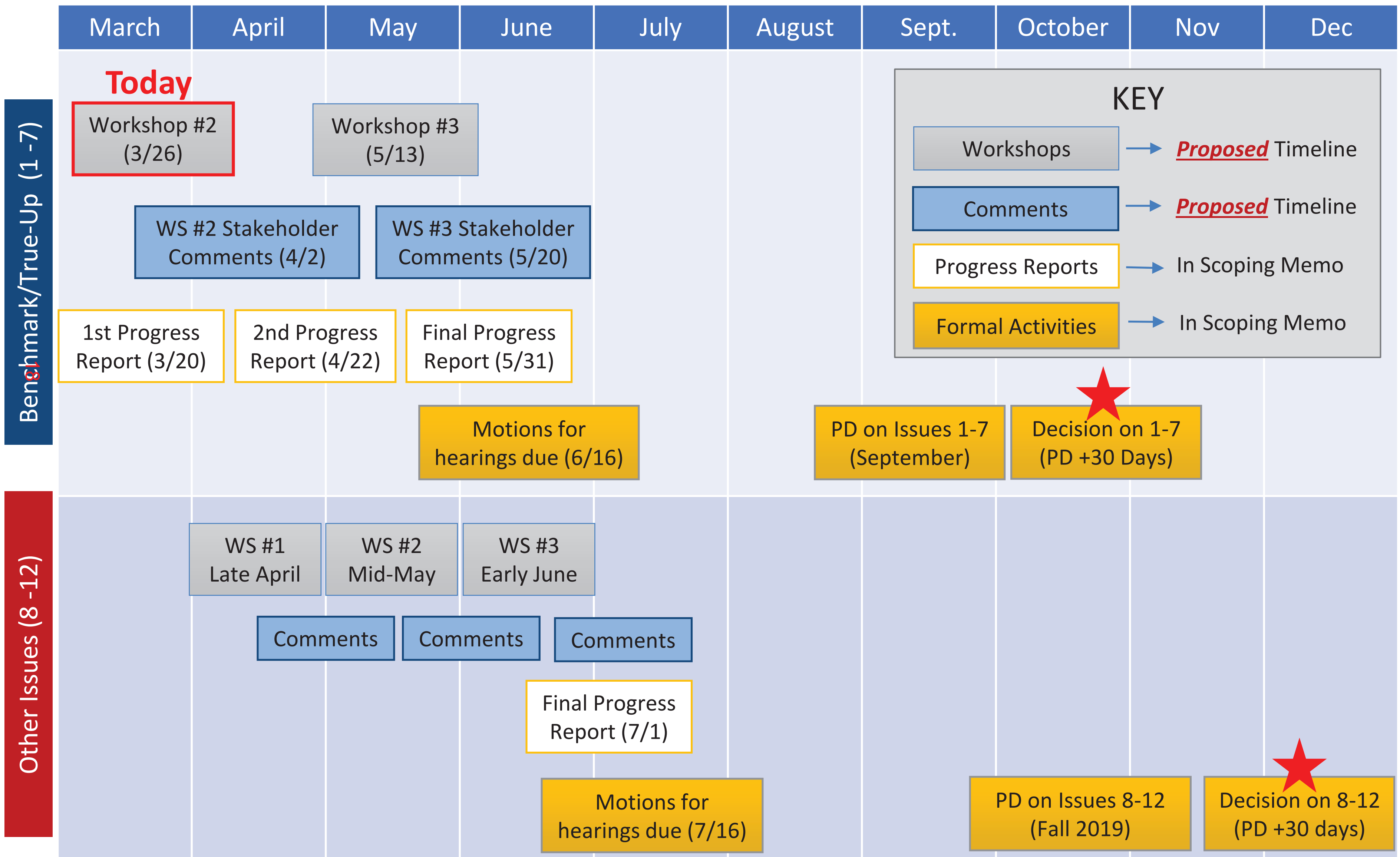
- AREM/DACC, CUE, City of San Diego, TURN, Commercial Energy, CLECA, IEPA
- Themes Included
  - Transition Timeline
  - Number and Type of MPBs
  - Timing of Data Request and Energy Division Benchmark Calculation
  - Data Template Issues
  - Data Inputs to RA and RPS Adders
    - Multi-year Local RA Requirement
    - Contract Extensions/Amendments in MPB
    - Transaction Types to Include in RA Adder (CPM)
    - Fixed-Price Bundled PPAs in RPS Benchmark
  - Unsold RA
  - Confidentiality

Two Meetings Were Held with Energy Division

- 3/7 and 3/19
- Focused on Reporting Templates and Timing

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Proposed 2019 Schedule for Working Group One



Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Updated Proposal

Updated Proposal

Benchmark and True-Up Mechanics / Timing

- **CCAs, ESPs and IOUs submit data on RA and RPS transactions to Energy Division on a <u>quarterly basis</u>[1]**
  - RA Data Response leverages existing Energy Division data template
  - RPS Data Response uses a new purpose-built data template
- **By November 1st each year, Energy Division will publish <u>two</u> separate sets of RA and RPS Adders**
  1. The "<u>Forecast</u>" RA/RPS Adders are used in setting the PCIA rates for the delivery year
  2. The "<u>Final</u>" RA/RPS Adders are used in truing up the imputed RA/RPS PABA entries for products used by the IOU's in the delivery year

[1] Based on input from Energy Division. CCAs are still evaluating.

Updated Proposal

Specifics of MPB Adder Calculations

- **RA Adder:** Includes market-based RA-only sales and purchases from IOU, CCA and ESP transactions
- **RPS Adder:** Includes market-based PCC1 “index-plus” sales and purchases from IOU, CCA and ESP transactions
- Energy Division to count the same (single) transaction between the same parties once for purposes of calculating the RA/RPS Adders

Key Changes Based on Stakeholder Feedback

Data Requests Frequency

- Quarterly to allow Energy Division time for data cleanup[1]
- Benchmarks still issued just once a year

Defining Number and Types of MPB

- **RPS**
  - One RPS adder for all IOUs
- **RA**
  - One System price for all IOUs
  - One Flex price for all IOUs
  - Local price per TAC area[2]

Multi-year Local RA

- MPB reflects three-year procurement timeline for local only

[1] Based on input from Energy Division. CCAs are still evaluating.
[2] Subject to aggregation, see discussion on slide 19.

Tomorrow's ERRA Forecast Calendar

Green = New Items

Updated Proposal

Only change from WS 1 is frequency of Data Responses from once a year to quarterly

★ LSEs Submit RA and RPS Data quarterly to Energy Division. Based on input from Energy Division. CCAs are still evaluating

Commission Activity

Energy Division Provides RA/RPS Adders to IOUs: (Nov)
- 2020 "Forecast RA/RPS Adder", <u>AND</u>
- 2019 "Final RA/RPS Adder"

2020 ERRA Forecast and 2020 PCIA Rates Approved (Dec.)

Energy Division Provides RA/RPS Adders to IOUs: (Nov)
- 2021 "Forecast RA/RPS Adder", <u>AND</u>
- 2020 "Final RA/RPS Adder"

2021 ERRA Forecast and 2021 PCIA Rates Approved (Dec.)

2019 (Year n-1) — 2020 (Year n) — 2021 (Year n + 1)

Investor-Owned Utility (IOU) Activity

2020 ERRA Forecast <u>Update</u> Filed, Includes **2020 PCIA Rates** (Nov)
- **2020 PCIA Rates Based on 2020 "Forecast RA/RPS Adder"**

2020 Rates Effective, Includes **2020 PCIA Rates** (Jan)

2021 ERRA Forecast Filed, Includes **2021 PCIA Rates** (Jun)

RA/RPS Adders True-Up (Nov)
- Products Used by IOU valued at **2020 "Final RA/RPS Adder"**

2021 ERRA Forecast <u>Update</u> Filed, Includes **2021 PCIA Rates** (Nov)
- **2021 PCIA Rates Based on "Forecast RA/RPS Adder" AND 2020 Under/Over Collection**

2021 Rates Effective, Includes **2021 PCIA Rates** (Jan)

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

"Forecast" Adders versus "Final" Adders

Updated Proposal[1]

- By Nov 1st each year, Energy Division will publish two separate Adders

Nov 1, 2019

Energy Division Publishes
- Final RA/RPS Adders for 2019 (Year n-1)
- **Forecast RA/RPS Adders for 2020 (Year n)**

Nov 1, 2020

Energy Division Publishes
- **Final RA/RPS Adders for 2020 (Year n)**
- Forecast RA/RPS Adders for 2021 (Year n+1)

"Forecast Adders" for Year n

Transaction Input Data:
- Transactions Executed in Year n-2 (Q4), and Year n-1 (Q1-Q3) for Delivery Year n
- Except for Local RA (see following slides)

Used by IOUs to:
- Forecast Market Value of PCIA Portfolio and Set PCIA Rate for Year n (2020)

"Final Adders" for Year n

Transaction Input Data[2]:
- Transactions Executed in Year n-1 (Q1-Q4) for Delivery Year n
- Augmented with Transactions Executed in Year n (Q1-Q3) for Delivery Year n
- Except for Local RA (see following slides)

Used by IOUs to:
- True-Up Imputed PABA Entries for Products Used by IOUs in Year n (2020)

(n-1) 2019

(Year n) 2020

[1] Joint Proposal differs from D.18-10-019; Potential update to Decision language

[2] For the "Final Adder", transactions from Q4 of n-2 are dropped, and Q1-Q3 of year n are added

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Local RA – Multi-Year Contracting Requirement

Proposal

- Local RA must be purchased on a three-year forward basis
- In Year "n-1" the LSE must meet Local RA requirements as follows:
  - 100% of year "n"
  - 100% of year "n+1"
  - 50% of year "n+2"
- Ordering Paragraph 1.c. of D.18-10-019 prescribes benchmark as average of RA purchases/sales in year "n-1" for year "n"
- For 2020, n-1 data will provide benchmark
- In order to include relevant transactions, in 2020 the calculation will use n-1, and in 2021 will use n-2. From 2022 on, the calculation will use n-3 and n-2.

Local RA – Multi-Year Contracting Requirement

		Delivery Year				
		2020	2021	2022	2023	2024
Purchase Year	2019	100%	100%	50%	-	-
	2020	-	-	50%	50%	-
	2021	-	-	-	50%	50%
	2022	-	-	-	-	50%
	TOTAL	100%	100%	100%	100%	100%

Responses to Stakeholder Feedback from Workshop #1:

Comments by Theme

Stakeholder Feedback by Theme

- Transition Timeline
- Number and Type of MPBs
- Timing of DR and Energy Division Benchmark Calculation
- Data Template Issues
- Data Inputs to RA and RPS Adders
  - Multi-year Local RA Requirement
  - Contract Extensions/Amendments in MPB
  - Transaction Types to Include in RA Adder (CPM)
  - Fixed-Price Bundled PPAs in RPS Benchmark
- Unsold RA
- Confidentiality

Transition Timeline Pending Decision Resolution

Stakeholder Comments

- **AReM/DACC**: Optimistic that only a month or two delay will be required. But if intractable delays occur, then recommend keeping same process as was used for 2019 (p. 5)

Response

- Co-Leads committed to meeting proposed timeline
- Co-leads do not support full year postponement
- If unresolved by ERRA forecast update, propose to delay filing and implementation a few months, as needed
  - Similar to delay for this year's ERRA implementation

Defining Number and Types of MPBs[1]

Stakeholder Comments

- **CUE**: Requests clarification on how the adders will be calculated geographically
- **City of San Diego**: Concerned that SDG&E TAC area only has one CCA and thus will be a thinly traded market (p. 5)
- **AReM/DACC**: States there should be different prices for each type of RA, and local should be by local area (p. 5)

Response

Resource Adequacy

- **System**: One price for all 3 IOUs
- **Flex**: One price for all 3 IOUs
- **Local**: One price for each TAC Area per D.18-10-019
  - Data may need to be aggregated to protect confidentiality (e.g., if less than a minimum number of counterparties, SDG&E local areas could be combined with SCE local areas into SP15)[2]

RPS

- One price for all 3 IOUs

[1]All MPBs would be published on both a Forecast and Final basis.
[2]Joint Proposal differs from D.18-10-019; Potential update to Decision language

Timing of Data Response and Energy Division Benchmark Publication

Stakeholder Comments

- **CLECA**: Energy Division should be given additional time to calculate the MPB adders (p. 2)
- **Energy Division**: In conversations held after the first workshop, Energy Division expressed preference for quarterly data submission

Response

- Proposal now reflects that data would be submitted quarterly, giving Energy Division enough time to clean between each iteration
- MPBs would still be published November 1
- Data will be a standing quarterly compliance item, rather than a data request from Energy Division
- Based on input from Energy Division. CCAs are still evaluating

Data Templates – Stakeholder Comments

Stakeholder Comments

- **AReM/DACC**:
  - Provided suggested revisions to assist LSEs and Energy Division staff
    - Include only the data needed to calculate the RA/RPS Adders
    - Include only the purchases, and not sales
  - Requested clarification/changes to the template
    - Remove the “month” data field
    - Clarify the description under the “volume” data field
- **CUE**:
  - Provided suggestions to increase clarity for parties
    - Stand-alone templates for purpose of calculating the RA/RPS Adders OR
    - Identify fields used for calculating the RA/RPS Adders

Data Templates - Coordination with Energy Division

Follow-Up Discussions with Energy Division Staff

- Co-Leads worked with Energy Division staff to develop a feasible process given the initial proposal of a short turnaround time
  - Minimize time for data clean-ups and LSE follow-ups
    - Minimize free-form data entries
    - Establish clear instructions and descriptions for the reporting requirements for LSEs
    - For the transition period, data request will be quarterly[1]. The RA/RPS Adders will continue to be published once per year in early November

Response

- RA: Use the modified data template
- RPS: Develop a stand-alone data template

[1] All based on input from Energy Division; CCAs are still evaluating.

RA Data Template – Modification of Current

Joint Proposal by Working Group One (Redline to Existing RA Data Template)

#	Data Field ~~Descriptions~~:	Data Field Description~~s~~:
1	Contract ID Between Parties	Insert the ~~LSE~~ parties' unique contract identifier
2	Month	From the drop-down, select the delivery month for which the price quoted is applicable; Please insert an additional row for each month regardless of whether capacity price or capacity MW amount changes between months
3	Year	From the drop-down, select the year of delivery
4	Resource Scheduling ID	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list. If you select "Unspecified or Not Operational" then you must fill out the Area and Zone fields
5	Resource Name	Name of resource; This field will automatically populate if you select a CAISO Resource ID
7	Buyer	Contract buyer; If the buyer is purchasing on behalf of another party or parties, list the actual buyer to the contract
8	Seller	Contract seller; If the seller is selling on behalf of another party or parties, list the actual seller to the contract
9	~~Generic~~ System Capacity Under Contract (MW)	The amount of ~~generic~~ System MW(s) under contract for the associated month and year of the contract
11	Flexible Capacity Under Contract (MW)	The amount of Flexible MW(s) under contract for the associated month and year of the contract; System and Flexible Capacity are a bundled product; Do not list a MW amount greater than the System MW amount
12	Price ($/kW-Month)	List the price in $/kW-Month format for each month and year of the contract even if the price is same for all months of the year; For example, if a contract covers a 3-year period, you will input 36 lines for the contract
13	Contract ~~Signed~~ Execution Date	List the date the contract ~~was originally signed~~ is executed~~; If there has been an extension signed you do not need to list that date~~ - MM/DD/YYYY
14	Type of Generation	Select whether the resource is new or existing generation; A repower will be considered new generation for this application
15	~~Combined Heat and Power (CHP) Contract~~	~~Select Yes if the contract is a CHP contract; Select No if the contract is not a CHP contract~~
16	Local Area	If you select "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, specify the Local Area; This field will automatically populate if you select a CAISO Resource ID
17	Zone	If you select "Unspecified" or "Not Operational Yet" as the CAISO Resource ID, specify the Zone; This field will automatically populate if you select a CAISO Resource ID

RPS Data Template – New Stand-Alone

Joint Proposal by Working Group One

#	Data Field:	Data Field Description:
1	**Contract ID Between Parties**	Insert the parties' unique contract identifier
2	**Year**	From the drop-down, select the year of delivery
3	**Resource Scheduling ID**	From the drop-down, select the CAISO Resource ID; Select "Unspecified" if your contract does not have a specified resource and select "Not Operational" if the resource you contracted with is not yet on the NQC list.
4	**Resource Name**	Name of resource; This field will automatically populate if you select a CAISO Resource ID
5	**Buyer**	Contract buyer; If the buyer is purchasing on behalf of another party or parties, list the actual buyer to the contract
6	**Seller**	Contract seller; If the seller is selling on behalf of another party or parties, list the actual seller to the contract
7	**PCC Classification**	The PCC classification under contract for the associated year of delivery
8	**Volumes**	List the forecasted or contracted volumes under contract for the associated year of delivery
9	**Price ($/MWh)**	List the price in $/MWh format under contract for the associated year of delivery; For REC + Energy (Index), provide the REC-only premium price
10	**Contract Execution Date**	List the date the contract is executed - MM/DD/YYYY

Subject to change based on open issues concerning RPS Adder calculation

Responses to Stakeholder Feedback from Workshop #1:

Data Inputs to RA and RPS Adders

Accounting for Multi-Year Local RA Procurement in the RA Adder

Stakeholder Comments

- **<u>City of San Diego</u>**:
  - Requests clarity on how multi-year local RA obligation will affect the benchmark and true-up (p. 4)
  - Concerned about over-procurement of local RA with a multi-year RA requirement based on first year's load (p. 4)

Co-Lead Response

- With the exception of Local RA, contracts executed outside of the transaction inclusion window will not be included in calculation of the MPBs
- The local RA MPB will be calculated based on a broader transaction window to reflect the multi-year requirement (see slides 14 and 15)
- The RA proceeding is addressing how to set multi-year local RA requirements

Contract Extensions/Amendments in MPB

Stakeholder Comments

- **TURN**: "the prices of contracts that are voluntarily extended by both parties should be assumed to be current as of the date of such an extension… contracts that are extended voluntarily by both parties should be considered as fresh market data for the year of the extension… Exclude such contracts that are not strictly market transactions but are instead negotiated with an eye toward changing the terms of a contract" (p. 5)

Response

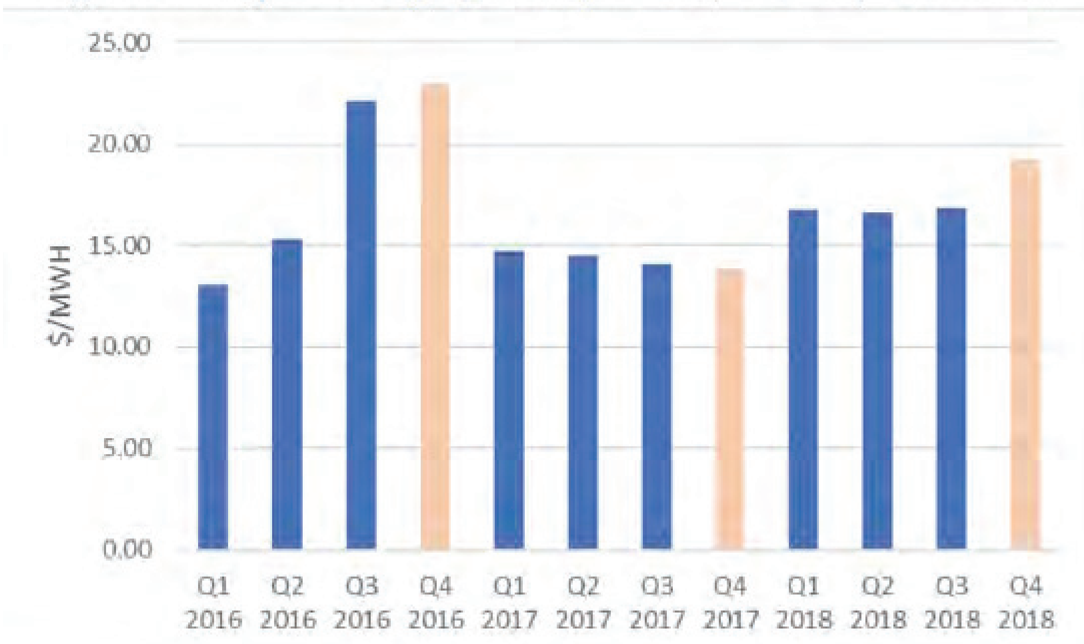
- Difficult to develop a rule that applies to all types of contract amendments
- Still evaluating this issue and will discuss at third workshop

Q4 REC Transactions for RPS MPB

Stakeholder Comments

- **<u>AReM/DACC</u>**: RPS transactions in Q4 of year n are not included in the benchmark. Platts data (below) suggests that price in Q4 may be higher. (p. 3-4)

Figure 2. Simple Average Quarterly PCC1 (Bucket 1) REC Prices



Q4 REC Transactions for RPS MPB

Response

- Still support use of transactions in Q1-Q4 of n-1 and Q1-Q3 of n for delivery in year n as sufficient for setting the final RPS adder and RA benchmark
- Appreciate the graph provided by AReM/DACC shows the price of transactions by quarter, but note the following:
  - the delivery period is not specified (e.g., transactions in Q4 in n may not deliver in n)
  - volumes are not provided
- For IOUs, RPS transactions require lengthy CPUC approval so it is unlikely that IOUs would be able to execute RPS transactions in Q4 of year n for delivery in year n

Inclusion of CPM in RA Adder

Stakeholder Comments

- **CLECA**: Does not support use of CPM in the RA adder as TURN's proposal did not include CPM and was adopted by decision (p. 2)

Positions to be Briefed

- **PG&E Position:**
  - Support CLECAs position not to include a backstop procurement price as the price for a forward compliance requirement
  - Any actual CPM revenues of PCIA-eligible resources are credited to PABA
- **CalCCA Position:** CPM costs assessed to LSEs are a cost for procuring RA and are appropriately included in the MPB.

Inclusion of Contracts with Optionality in MPB

Stakeholder Comments

- **CUE**: “Are all contracts that include optionality excluded from the calculation? If not, how will the transaction price reflect the optionality including any premium payments? If contracts with optionality are excluded, it would be useful for the data template or instructions for the data template to indicate this.” (p. 3)

Response

- The PCIA OIR decision did not specify any “optionality” adjustment in the adopted formula for calculating the MPB nor did it address the exclusion of contracts with “optionality”.
- In future comments, please describe more about “optionality” within this context.

Including Bundled Contracts in RPS MPB

Stakeholder Comments

- **AReM/DACC**: Explore if and how to include bundled contracts. Proxy delivery shapes and known NQC. Acknowledges difficulty and risk of getting it wrong. If can't reach agreement, would accept RA only and index plus for RPS (p. 2-3)
- **CUE**: Seeks to understand why including fixed-priced bundled PPAs is not viable or less preferable than an index plus approach (p. 2)
- **TURN**: Index plus approach limits the 'market' to short term transactions, does not reflect bundled PPAs priced below brown power index, and may expose the MPB to volatility if prices vary substantially throughout RPS compliance periods. Index plus approach may not represent market activity if multi-year strips are being sold to meet 65% long-term requirement. The value of RPS may be derived from a fixed-price PPA by extracting the value of RA and NQC. Fixed-price contracts for new facilities should be counted in MPB starting with the first year of commercial operation and continue for three years (p. 2-5)

Including Bundled Contracts in RPS MPB

Response

- **Maintain preference for PCC 1 “index-plus” informed MPB**
  - Administratively simpler to calculate
  - Represents the market value of RECs
  - Represents the monetization of the portfolio. Parties currently seem unwilling to take on entire PPAs but there is a lot of market interest in PCC 1 index-plus
  - Could revisit in 2 years if market dynamics change. Energy Division could publish a threshold if not enough transactions are present to revisit.
- **Challenges if including fixed-price PPAs**
  - Administrative calculations have a propensity to deviate from market reality
  - Index-plus and fixed-price contracts have different units (Floating $/Energy + Fixed $/REC vs. Fixed $/Energy + REC), can’t be calculated/averaged easily. Energy value in index plus transactions nets out in settlement.
  - Significant lag between execution and online date results in stale prices

Accounting for Forecasted and Actual Unsold RA Capacity

Where to Forecast Value of Unsold RA: MPB Price vs. ERRA Forecast Volumes

Language from Scoping Memo

7. D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." . . .

Proposal

- Capacity expected to remain unsold should be accounted for in the forecasted volume of unsold RA in each IOU's ERRA Forecast filing, rather than adjusting the forecasted RA MPB to reflect *de minimis* value.
- This maintains the RA adder as a price based solely on actual transactions.[1]
- This approach was used by SCE in their 2019 ERRA Forecast.

[1] Joint Proposal differs from D.18-10-019; Potential update to Decision language

Forecasting Amount / Volume of Unsold RA

Language from Scoping Memo

6. How should the Commission clarify/define forecasting amounts of unsold RA?

Potential Strawman Framework for Discussion Purposes Only (Not Formal Proposal)

- For the ERRA Forecast, a forecast based on the previous year's unsold volume +/- a volume corresponding to the change in the IOU's load forecast (Reasonable Range) will be presumed reasonable
- IOUs forecasting an unsold volume above or below the Reasonable Range must provide an explanation in their ERRA filing, which may be contested by intervenors
- Forecasted volumes will be subject to a true-up to actuals

Zero or De Minimis RA Value - *ERRA Forecast*

Language from Scoping Memo

7. . . . Are further parameters needed to define a *de minimis* price (for RA expected to remain unsold), and if so, what are these parameters?

Stakeholder Comments

- **CLECA**: Suggested 5%-10% of the contract price should be the de minimis value of unsold RA (p. 5)
- **AREM/DACC:** "RA that is [not][2] sold or used for IOU compliance should be valued at [zero], with the following exception: if any LSE cannot purchase RA and must file for a waiver and the IOU has unsold volumes of that type of RA, then the unsold RA should be valued at the CPM soft offer cap in the benchmark." (p. 5-6)
- **CalCCA Proposal**:
  - Capacity that remains unsold due to the IOU's rejection of bids below the IOU's price floor will be valued at the price floor as the de minimis price.
  - Capacity that remains unsold, subject to the conditions specified on slide 39, will be valued at zero.
- **PG&E Proposal**:
  - Regardless of any de minimis price for RA expected to remain unsold, RA that is ultimately unsold and is not used or reserved by the IOUs, should be assigned a value of $0 in the true-up.

[1] Joint Proposal differs from D.18-10-019; Potential update to Decision language
[2] Original comments by AReM/DACC omitted word "not".

Volume and Price of Unsold RA - *PABA True-Up*

CalCCA Proposal:

- A MW of RA capacity may be counted as "unsold" to the extent it
  - (1) exceeds the utility's forecast needs for bundled customers plus an agreed upon level of RA reserved by IOU;
  - (2) the utility made the capacity available to the market, either through an RFO or an Electronic Bulletin Board; and
  - (3) the utility did not impose a price floor in the sale of the capacity, or if a price floor was used, the price floor becomes the de minimis value.
- Unless these three conditions are met, the capacity will be valued at the benchmark in the same way that compliance plus reserved volumes are valued.

PG&E Proposal:

- Unsold capacity that was offered to the market and is not used by the utility (either for compliance or as a reserve) should be trued up to $0.

Confidentiality

Stakeholder Comments

- **AReM/DACC**: Proposes that only individuals within Energy Division tasked with calculation have access to data; should be destroyed or returned following calculation (pg 4)
- **CLECA**: Supports destruction of LSE data responses and acknowledges auditing would require resubmission of data (pg 5)
- **Commercial Energy**: Proposes only Energy Division staff directly responsible to calculating RA and RPS adders should have access to data responses (pg 2). After calculating the benchmark, data should be destroyed or returned (pg 2)
- **IEPA**: Confidentiality of data must be protected, and benchmarking should not become a method for market participants to seek price discovery. Commission should clarify confidentiality rules (pg 2)

Confidentiality

Response

- Ruling issued by ALJ Atamturk on March 20 states that data submitted to Energy Division by IOUs, ESPs, and CCAs entitled to confidentiality protections under D. 06-06-066
- Destruction of data after a 3-year period would prevent audit of past calculations

Responses to Stakeholder Feedback from Workshop #1:

Requests for Clarification

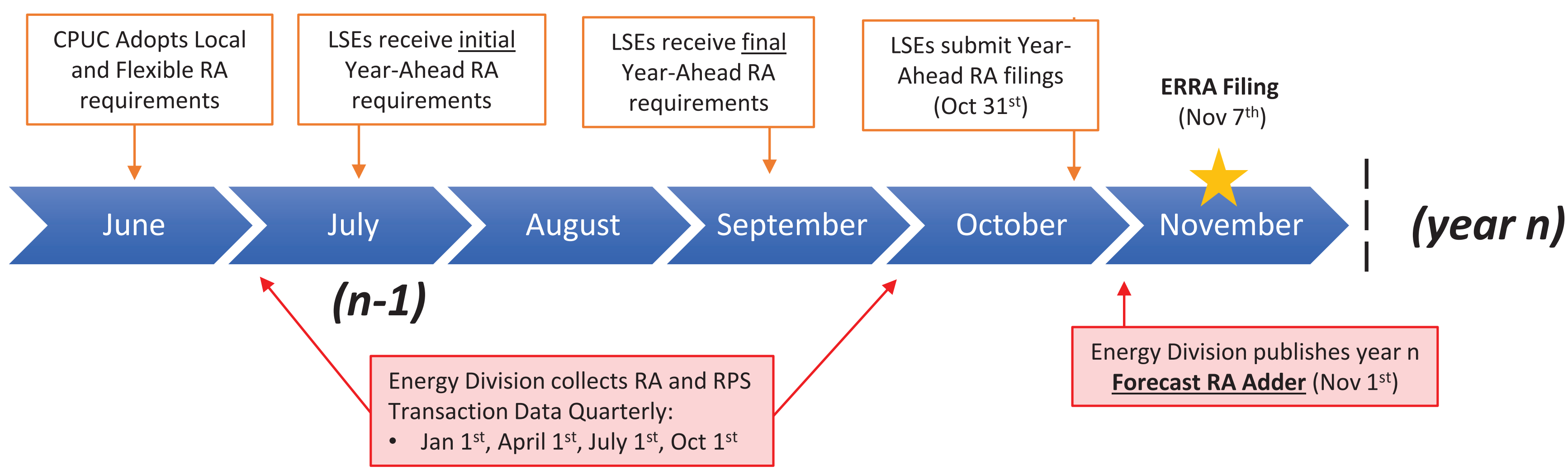
Expanded RA Compliance Timeline

Stakeholder Comments

- **<u>City of San Diego</u>**: Requested expanded timeline with RA reporting deadlines (p. 3)

Response

- RA Timeline below with Energy Division data collection and MPB publishing schedule



Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

Clarification on Use of “Forecast” & “Final” MPB

Stakeholder Comments

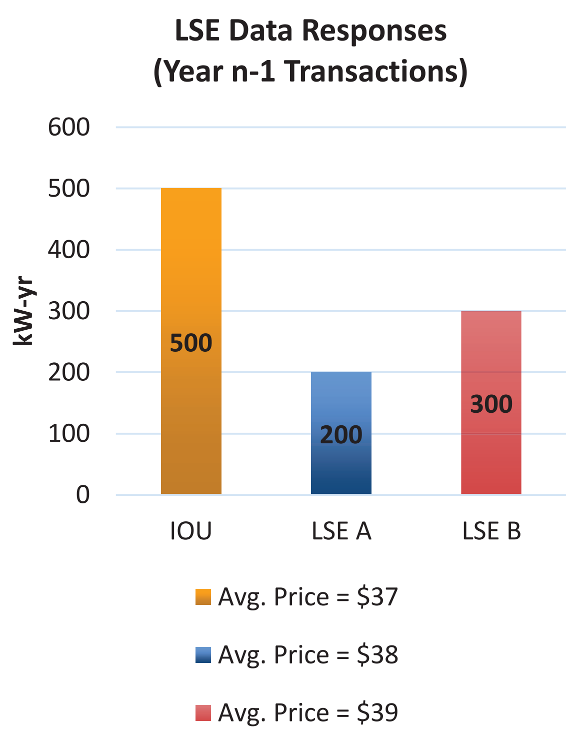
- Some parties requested clarification on how the Final RA Adder would be applied in the true-up.

Response

- PG&E has provided an illustrative example (focused on RA) developed to demonstrate calculation and use of both the *Forecast* and *Final* RA Adders.

1. Energy Division Calculates *Forecast* RA Adder

- LSE's submit transactions executed in year n-1 to Energy Division
- Energy Division uses data responses to calculate *Forecast* RA Adder



Energy Division Calculation

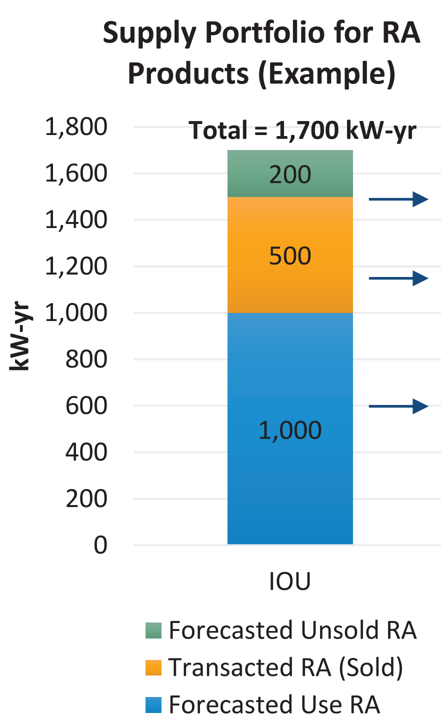
	Transacted Quantity (kW-yr)	Average Price ($/kW-yr)	Total Transacted Value ($)
IOU Year n-1 Sales	500	$ 37.00	$ 18,500
LSE A Year n-1 Sales	200	$ 38.00	$ 7,600
LSE B Year n-1 Sales	300	$ 39.00	$ 11,700
Total	**1,000**		**$ 37,800**

$$\frac{\text{Transacted Value}}{\text{Transacted Quantity}} = \frac{\$37{,}800}{1{,}000\text{ kW-yr}} = \boxed{\textbf{RA Adder} = \$37.80/\text{kW-yr}}$$

2. IOUs use *Forecast* RA Adder to Forecast Mkt Value

In ERRA Filing, each IOU Calculates Market Value of PCIA Portfolio

- Forecasted Unsold valued @ zero or de minimis price
- Year n-1 Transactions valued @ Transacted Value
- Forecasted Use RA[1] valued @ *Forecast* RA Adder



Forecasted Unsold RA
200 kW-yr @ $0.00/kW-yr

Year n-1 Transactions (Sold)
500 kW-yr @ $37.00/kW-yr

Forecasted Use RA for IOU
1,000 kW-yr @ $37.80/kW-yr

	Quantity (kW-yr)	Value Assigned ($/kW-yr)	Market Value ($)
Forecasted Unsold RA	200	$ -	$ -
Transacted RA (Sold)	500	$ 37.00	$ 18,500
Forecasted Use RA	1,000	$ 37.80	$ 37,800
Total Market Value			**$ 56,300**

[1] Forecasted Use RA = Forecasted compliance plus amount reserved by IOU

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

3. PCIA Forecast for Year n

- Forecasted Costs and Market Value used to set the PCIA for year n

1. Forecast Total RA Portfolio Costs for Year n

Total RA Portfolio (kW-yr) * Portfolio Costs[1] ($/kW-yr) = Total Forecasted Costs of RA Portfolio

Total RA Portfolio (kW-yr)	Portfolio Costs ($/kW-yr)	Total Forecasted Costs ($)
1,700	$ 40.00	$ 68,000

2. Calculate Above Market Costs for year n

+ Total Forecasted Costs	$ 68,000
+ Total Market Value	$ (56,300)
= Above Market Costs	$ 11,700

3. Forecast Total IOU System Load[2]

+ Bundled Load (kWh)	200,000
+ Departed Load (kWh)	200,000
= Total Load (kWh)	400,000

4. Above Market Costs / Total Load = PCIA Rate for year n

$$\frac{\text{Above Market Costs (\$)}}{\text{Total Load (kWh)}} = \frac{\$\ 11{,}700}{400{,}000} = \boxed{\text{PCIA Rate year n} = \frac{\$0.02925}{\text{kWh}}}$$

1. This numerical example assumes the ACTUAL average price of RA in the IOU portfolio to be $40.00/kW-yr.
2. A 50/50 split between bundled and departed load is representative of PG&E's 2019 ERRA forecast.

4. Energy Division Calculates *Final* RA Adder

- LSE's submit additional transactions conducted in year n
- Energy Division uses both n-1 and year n sales to calculate *Final* Adder

Energy Division Calculation

		Transacted Quantity (kW-yr)	Average Price ($)	Total Transacted Value ($)
IOU	Year n-1 Sales	500	$ 37.00	$ 18,500
IOU	Year n Sales	100	$ 41.00	$ 4,100
LSE A	Year n-1 Sales	200	$ 38.00	$ 7,600
LSE A	Year n Sales	50	$ 42.00	$ 2,100
LSE B	Year n-1 Sales	300	$ 39.00	$ 11,700
LSE B	Year n Sales	75	$ 43.00	$ 3,225
	Total	**1,225**		**$ 47,225**

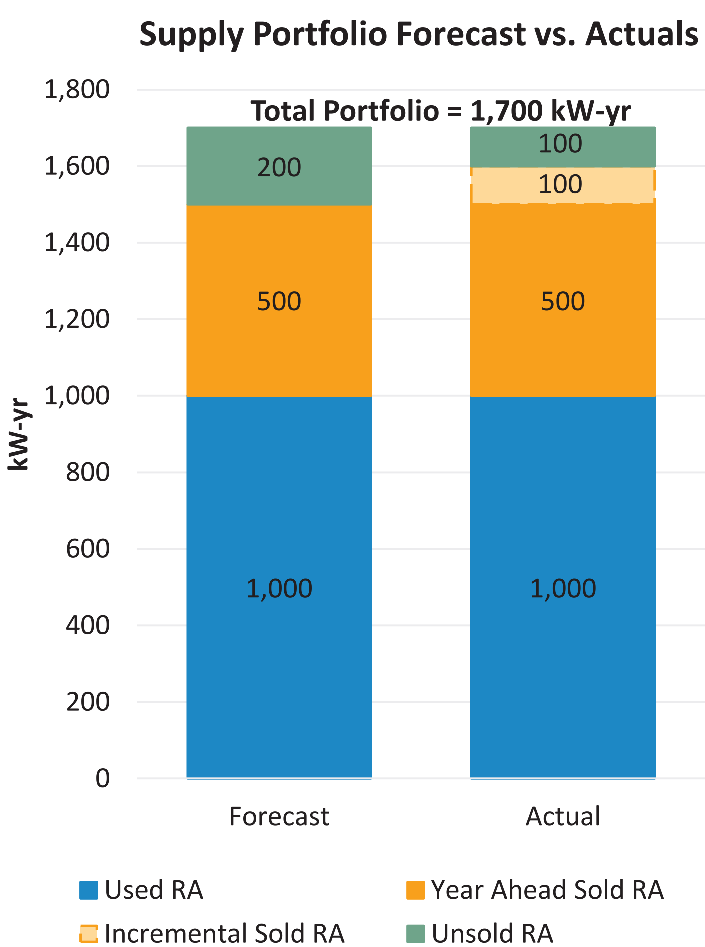
$$\frac{\text{Transacted Value}}{\text{Transacted Quantity}} = \frac{\$\ 47{,}225}{1{,}225\ \text{kW-yr}} =$$

Final RA Adder = $38.55/kW-yr

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

5. Final Disposition of RA Portfolio vs. ERRA Forecast

- IOU may execute incremental sales in year n, thus reducing final remaining Unsold RA



Final Remaining Unsold RA (100 kW-yr)
Valued @ $0.00/kW-yr

Incremental Year n Sales (100 kW-yr)
Valued at Actual Transacted Price
$41.00/kW=yr

Year n-1 Sales (500 kW-yr)
Valued at Actual Transacted Price
$37.00/kW-yr

Used by IOU (1,000 kW-yr)
Valued at *Final* RA Adder
$38.55/kW-yr

6. PABA Entries for Year n and Final Balance (i.e. "The True-Up")

- All entries record actual costs/revenues EXCEPT for RA used by IOU, which is valued at the *Final* RA adder
- A negative balance in PABA represents an over-collection which will reduce the PCIA calculated for year n+1

Quantity * Value = PABA Entry

60

PABA Categories	Quantity	Unit	Value	Unit	PABA Entries	Source of Cost or Revenue
+ Total RA Costs	1,700	kW-yrs	$ 40.00	$/kW-yr	$ 68,000.00	Actual Settled Invoices for PCIA-Eligible RA Contracts
- Year Ahead RA Sales	500	kW-yrs	$ 37.00	$/kW-yr	$ (18,500.00)	Actual Year-Ahead Sales Revenue
- Incremental RA Sales	100	kW-yrs	$ 41.00	$/kW-yr	$ (4,100.00)	Actual Incremental Sales Revenue
- Value of RA Used by IOU	1,000	kW-yrs	$ 38.55	$/kW-yr	$ (38,551.02)	Debit entry to ERRA, Credit to PABA
- Value of Unsold RA	100	kW-yrs	$ -	$/kW-yr	$ -	
- PCIA Revenue	400,000	kWh	$ 0.02925	$/kWh	$ (11,700.00)	Departed - Billed PCIA Bundled - Portion of Gen
= EOY PABA Balance					**$ (4,851.02)**	

7. Year n PABA Balance Used in Setting n+1 PCIA

- In this example, carrying forward the PABA balance from year n *REDUCES* the PCIA rate for year n+1 by $0.01213/kWh
- PABA Balance can increase *or* decrease following year's PCIA

1. Calculate Above Market Costs for Year n+1[1]

+ Total Forecasted Costs (n+1)	$	68,000
+ Total Market Value (n+1)	$	(56,300)
+/- PABA Balance (from year n)	$	(4,851)
= Above Market Costs (n+1)	$	6,849

2. Calculate PCIA Rate for Year n+1

$$\frac{\text{Above Market Costs (\$)}}{\text{Total Load (kWh)}} = \frac{\$\ 6{,}849}{400{,}000\text{ kWh}} = \boxed{\text{PCIA Rate year n+1} = \frac{\$0.01712}{\text{kWh}}}$$

Compare to year n PCIA Rate of $0.02925/kWh

Impact of Including year n PABA Balance in n+1 PCIA Rate

$$\frac{\text{PABA Balance from year n (\$)}}{\text{Total Load in n+1 (kWh)}} = \frac{\$\ (4{,}851)}{400{,}000\text{ kWh}} = \boxed{\text{Impact to n+1 PCIA Rate} \quad \frac{\$\ (0.01213)}{\text{kWh}}}$$

Recap and Next Steps

Scoping Memo Guidance

Primary Focus of March 26th Workshop

- **Benchmark and True-Up Mechanism**

(Scoping Memo 2.1.1 – 2.1.5):

1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark? [Slides 12, 13, 49]
2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission? [Slides 9, 12, 13]
3. Should the true up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true up process be addressed? [Slide 12]
4. Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark? [Slides 11, 12, 14, 44, 47]
5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how? [Slides 12, 22-24]

Scoping Memo Guidance (Cont'd)

Primary Focus of March 26th Workshop

- **Benchmark and True-Up Mechanism**

  (Scoping Memo 2.1.6 – 2.1.7):

  6. How should the Commission clarify/define forecasting amounts of unsold RA? [Slides 36, 38]
  7. D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a *de minimis* price, and if so, what are these parameters? [Slides 35, 37]

Proposed First Workshop late April

- **Other Items** (Scoping Memo questions 8-12)
  - Forecasting Departed Load
  - Vintage-Specific Billing Determinants
  - PCIA presentation on customer bills

Focus Questions for Non-Consensus Items

Please address the following questions in your written comments

Procedural

1. What are your thoughts on number of workshops (3) and proposed schedule to address items Scoping Memo issues 8-12?

Number and Type of MPBs

2. For aggregating Local RA, what is the appropriate number of transactions, and/or LSEs that should be represented before aggregating the resulting MPB to preserve confidentiality and/or market power?

Data Inputs to RA and RPS Adders

3. Please provide comments on proposal to account for multi-year procurement of Local RA in the MPB.
4. Should contract extensions/amendments be used to calculate the MPB. If so, please define a framework for which transaction should be included.
5. Should CPM backstop procurement from the CAISO be included in calculation of the RA Adder? Why or why not?
6. Should local resources transacted for System RA needs be included in the Local RA MPB.
7. Acknowledging the challenges of doing so, should the co-leads continue to work at developing a methodology to include fixed-price PPAs in the RPS MPB?

* Joint Proposal differs from D.18-10-019; Potential update to Decision language

Focus Questions for Non-Consensus Items

Please address the following questions in your written comments

Unsold RA

8. Please comment on the strawman proposal to forecast amounts / volumes of unsold RA in each IOUs ERRA Forecast Proceeding by comparing to the previous year’s unsold amount.

9. For capacity expected to remain unsold in the PCIA forecast, what is an appropriate de minimis value? If proposing a value other than zero, please explain methodology for arriving at such value.

10. For capacity that remains unsold, what is an appropriate value to be used in the true-up? If proposing a value other than zero, please explain methodology for arriving at such value.

Other

11. Please feel free to comment on any other issues presented at this workshop.

* Joint Proposal differs from D.18-10-019; Potential update to Decision language

Q&A and Discussion

Comments on Workshop #2 Due:
Tuesday, April 2, 2019

Appendix

Other Stakeholder Feedback

Load Forecasting

Stakeholder Comments

- **City of San Diego**: Requests that next iteration of proposal reflect expectation that San Diego will depart bundled service (p. 3)

Response

- Load forecasting issues will be addressed at the next workshop

Informal Comments in Progress Report

Stakeholder Comments

- **CLECA**: Requested that informal comments be attached to the Progress Report

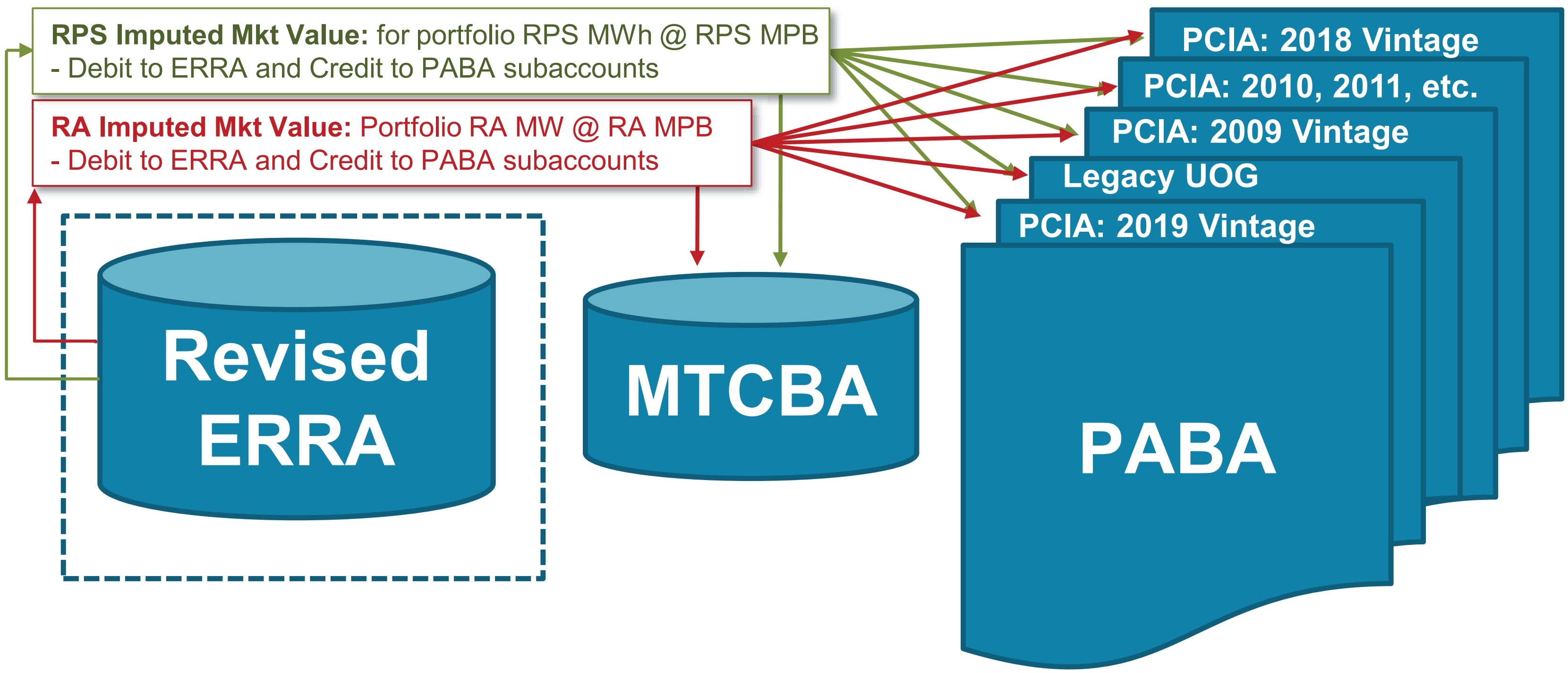
Response

- Comments were attached to the March 20 progress report and will be going forward

Details of Imputed PABA Entries for RA and RPS Used by IOUs

PABA Imputed Entries at Forecast and Final MPBs

On a monthly basis, Forecast MPBs will be used to accrue entries related to IOU use of RA and RPS portfolio. Trued up with Final MPBs at end of year



RPS → RPS Position (MWh) X *Forecast* RPS MPB ($/MWh) = RPS IOU Use Value

RA → RA Position (MW) X Forecast RA Adder ($-kW/year)/12 = RA IOU Use Value

Illustrative Monthly RA Entries for PABA

Legend
RA MPB Forecast and RA Compliance Value
RA Sales Price and RA Sales Value
RA MPB Final and RA Compliance Value
RA MPB True-up and RA Compliance Value True-up

Line No.	PCIA Revenue		Annual Total	January	February	March	April	May	June	July	August	September	October	November	December
1		Sales	400,000	33,000	33,000	33,000	33,000	33,000	32,000	35,000	35,000	35,000	32,000	33,000	33,000
2		PCIA Rate	(0.02925)												
3		PCIA Revenue	($11,700)	-$965	-$965	-$965	-$965	-$965	-$936	-$1,024	-$1,024	-$1,024	-$936	-$965	-$965

Line No.	SUPPLY Position & Cost			January	February	March	April	May	June	July	August	September	October	November	December
4		Portfolio (kW)	1,700	1,680	1,680	1,680	1,680	1,680	1,800	1,920	2,040	2,040	1,560	1,440	1,200
5		Portfolio Costs ($/kW-yr)	$40.00												
6		Portfolio Costs	$68,000	$5,600	$5,600	$5,600	$5,600	$5,600	$6,000	$6,400	$6,800	$6,800	$5,200	$4,800	$4,000

Line No.	Portfolio Usage		Annual Average	January	February	March	April	May	June	July	August	September	October	November	December
7	RA Volume (MW)	Compliance	940	840	840	840	900	900	1,080	1,020	1,080	1,080	900	900	900
8		Compliance Buffer	60	60	60	60	60	60	60	60	60	60	60	60	60
9		Sales	600	600	600	600	600	720	600	840	840	720	480	360	240
10		Unsold	100	180	180	180	120	0	60	0	60	180	120	120	0
11		Total	1,700	1,680	1,680	1,680	1,680	1,680	1,800	1,920	2,040	2,040	1,560	1,440	1,200

Line No.	Market Price Benchmark			Market Price Benchmark ($/kW-Year)											
12	Pricing	MPB Forecast		($37.80)	($37.80)	($37.80)	($37.80)	($37.80)	($37.80)	($37.80)	($37.80)	($37.80)			
13		Sales Price		($37.00)	($41.00)	($41.00)	($37.00)	($37.00)	($37.00)	($37.00)	($37.00)	($37.00)	($37.00)	($37.00)	($37.00)
14		MPB Final											($38.55)	($38.55)	($38.55)
15		True-up MPB											($0.75)		

Line No.	Portfolio Value		Annual Total	Monthly Value ($1000s)											
16	RA Value = Position X Price/12	Compliance	($35,701)	($2,646)	($2,646)	($2,646)	($2,835)	($2,835)	($3,402)	($3,213)	($3,402)	($3,402)	($2,891)	($2,891)	($2,891)
17		Buffer	($2,279)	($189)	($189)	($189)	($189)	($189)	($189)	($189)	($189)	($189)	($193)	($193)	($193)
18		Sales	($22,600)	($1,850)	($2,050)	($2,050)	($1,850)	($2,220)	($1,850)	($2,590)	($2,590)	($2,220)	($1,480)	($1,110)	($740)
19		Zero Value	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
													Jan-Sept		
20		Prior Period Adjustment MW											9,120		
21		Prior Period Adjustment Value	($570)										($570)		
22		Total	($61,150)	($4,685)	($4,885)	($4,885)	($4,874)	($5,244)	($5,441)	($5,992)	($6,181)	($5,811)	($5,134)	($4,194)	($3,824)

Line No.	PABA		Annual Total	Market Price Benchmark ($/kW-Year)											
23	Entries	PCIA Revenue	($11,700)	($965)	($965)	($965)	($965)	($965)	($936)	($1,024)	($1,024)	($1,024)	($936)	($965)	($965)
24		Portfolio Cost	$68,000	$5,600	$5,600	$5,600	$5,600	$5,600	$6,000	$6,400	$6,800	$6,800	$5,200	$4,800	$4,000
25		Portfolio Value - Compliance	($38,550)	($2,835)	($2,835)	($2,835)	($3,024)	($3,024)	($3,591)	($3,402)	($3,591)	($3,591)	($3,084)	($3,084)	($3,084)
26		Portfolio Value - Sales	($22,600)	($1,850)	($2,050)	($2,050)	($1,850)	($2,220)	($1,850)	($2,590)	($2,590)	($2,220)	($1,480)	($1,110)	($740)
27		Total	($4,850)	($50)	($250)	($250)	($239)	($609)	($377)	($616)	($405)	($35)	($300)	($359)	($789)

Concerns about proposed renewable benchmark

Market Price Benchmark Workshop
R.17-06-026
March 26, 2019

The Utility Reform Network

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Concerns with Index-based renewable benchmark

Omits increasingly significant transaction volumes

- Index-based transactions typically limited to short-term procurement
- Increasing reliance on long-term bundled PPAs (65% RPS requirement)

Does not reflect the pricing structure for bundled IOU PPAs

- New bundled long-term contracts should be available for comparison

Links renewable benchmark to brown power markets

- Assumes renewables always trade at a premium to short-term brown power prices
- Questionable relationship between short-term swings in brown power prices, which may be driven by changes in gas prices, and the price of new long-term PPAs
- Long-term PPA prices are based on costs of building/owning/operating new renewable generation, not short-term brown power prices

Volatility of short-term renewable power prices

- Short-term renewable procurement prices are affected by gas prices, RPS supply/demand balance, and RPS compliance deadlines

TURN alternative approach

Consider all relevant executed transactions

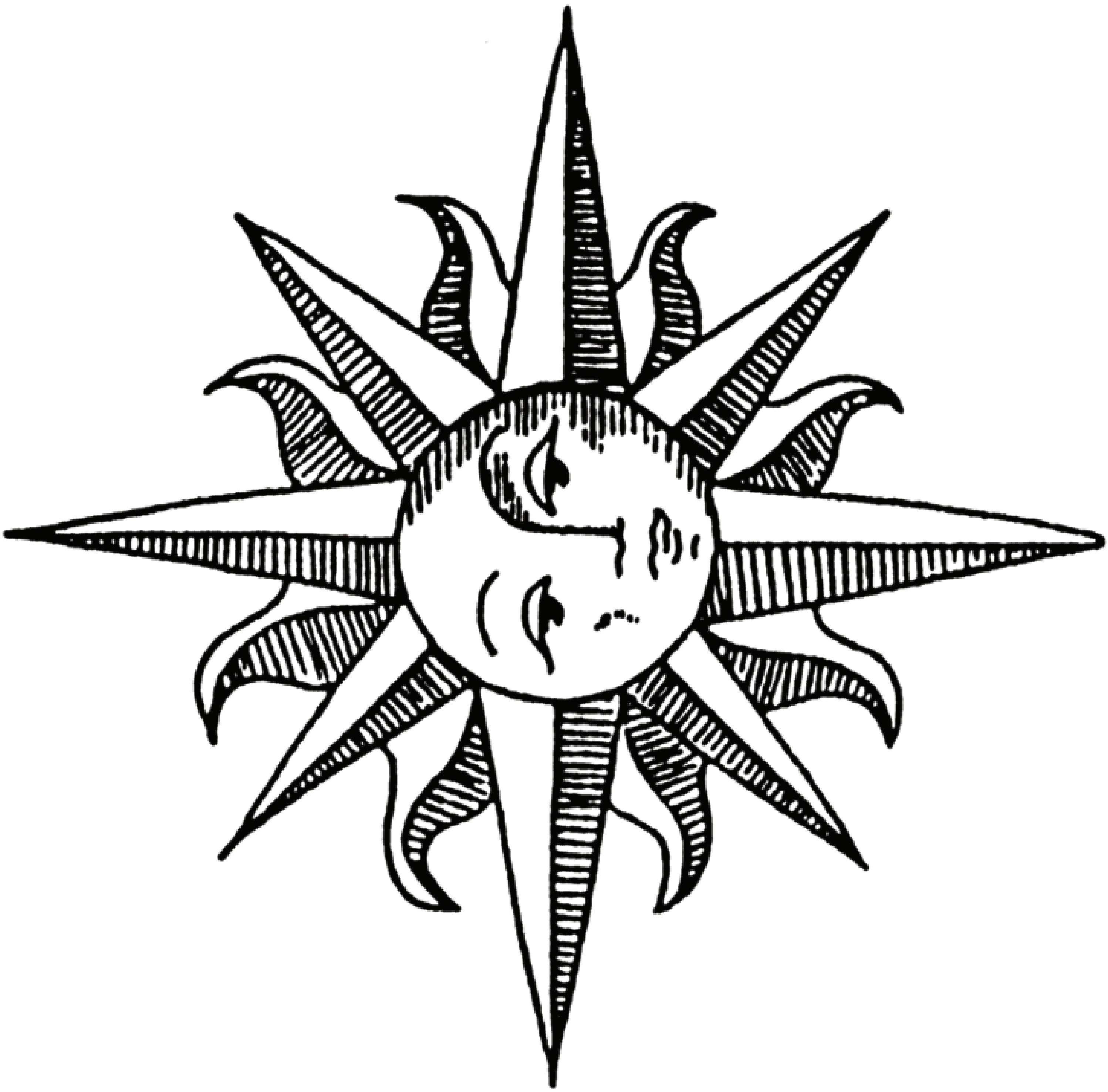
- Bundled PPAs executed in year n-2/n-1 for delivery in years n/n+1/n+2
- Index-based short-term transactions executed in year n-2/n-1 for delivery in year n
- Omit PPAs resulting from mandatory procurement (e.g. forest biomass)
- Since legacy PPAs are almost entirely bundled/long-term/fixed price, it may be appropriate to limit benchmark to new long-term bundled PPAs if sufficient volumes of transactions are available.

RA value for new RE contracts used in MPB

- Based on whether transaction is energy-only or includes RA value
- Apply monthly NQC or existing ELCC for contracts with future deliveries
- Use RA benchmark value for contracts that include RA

Energy + REC value

- For bundled fixed-price PPAs, "renewable energy" benchmark set based on bundled (energy + REC) fixed price net of any RA value
- Benchmark may consider hourly production profile for executed PPAs
- For index-based purchases, use brown power prices plus REC price



APPENDIX C

List of Attendees

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP #1 STRAW PROPOSAL (WORKSHOP #2)

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April 2, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP #1 STRAW PROPOSAL (WORKSHOP #2)

The Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC) appreciate the effort that was clearly made by PG&E and CalCCA and the other parties in this proceeding in refining the Straw Proposal initially presented at the March 1 workshop. AReM/DACC also welcome the opportunity to respond to the updated Straw Proposal presented at the March 27 Workshop and look forward to working through the remaining issues in the upcoming workshops. We continue to be optimistic that the parties will be able to come to consensus on many of the thorny issues that have been so well laid out.

I. COMMENTS ON THE REPORTING TEMPLATE AND PROTOCOLS

The updated straw proposal suggests that all load serving entities (LSEs) under CPUC jurisdiction submit completed Resource Adequacy (RA) and renewable portfolio standard (RPS) templates to the Energy Division (ED) on a quarterly basis (Presentation page 9). This differs from the original straw proposal, which suggested annual reporting in October of each year. AReM/DACC strongly prefer the annual reporting requirement. Reporting quarterly—on top of all the other reporting requirements—is burdensome. AReM/DACC acknowledge that the compilation of the data and the calculation of the respective benchmarks is significant task, however, through the use of well-designed templates and clear reporting instructions, AReM/DACC believe that one month should be sufficient for Energy Division to complete the task. We believe that the changes to the templates being proposed by this Working Group will make data compilation much easier and urge the Commission to focus on improving data inputs, not increasing the timing of inputs.

With respect to template design, AReM/DACC suggest the following. First, AReM/DACC applaud the recommendation to utilize drop-down menus and other similar template features to streamline the reporting and ensure that the reports are consistent across all LSEs. Doing this should minimize the time and effort required of Energy Division (ED) staff to compile the data and develop the benchmarks.

Second, AReM/DACC reiterate their recommendation to include contract price reporting for RA and RPS purchases only and exclude contract price reporting for RA and RPS sales, except when the sales data is from contracts pursuant to which an LSE under CPUC jurisdiction sells products to a non-CPUC jurisdictional entity, such as a municipal utility or irrigation district. This recommendation, too, should assist ED staff in calculating the benchmarks in a timely fashion.

Third, AReM/DACC note that the sample RA template (presentation page 23) did not appear to provide for reporting the MW of local RA under contract, only the local area. A row should be added for Local MW, similar to what is done for System and Flex RA.

Fourth, under "Volumes" for the RPS template, staff should clarify that forecasted volumes are what is desired to reflect the actual delivery expected from the contract. "Contracted" volumes could be very different than what is actually delivered if it only reflects an absolute minimum that the project will provide, and thus could skew the input basis for this contract.

II. COMMENTS ON USE OF BUNDLED CONTRACTS IN THE RPS BENCHMARK

In the informal comments to the opening workshop, AReM/DACC noted additional effort is needed to explore if, and how, to include bundled contracts (i.e., contracts which specify a single price even though they contract provides for energy plus RA and/or RPS) when estimating RA and RPS adders.[1] In that spirit, AReM/DACC appreciates TURN's effort to suggest a way to include the use of contracts in which energy plus RA and/or RPS is included in a single energy price. However, AReM/DACC is concerned that the TURN's straw suggestion does more to illustrate the challenges of including long-term single-price contracts than it does solve those challenges. As AReM/DACC understands, the TURN suggestion would value single-price long-term energy+RPS contracts in an IOU's Total Portfolio using a new Market Price Benchmark based on newly-entered into single price energy+RPS contracts. The advantage of this would be the elimination of the need to back out an implicit value of one element of the contract (generally assumed to be RPS) by setting the value of the other element(s) of the contract (generally assumed to be energy and perhaps RA).

However, this does not solve the other issues in inferring an RPS value, and even introduces the equally thorny issues. A few of the remaining challenges include:

- How might the protocol address the time delay between signing a PPA (which would reflect the expected prices when the contract begins delivery) and when it actually begins delivery?
- For this approach to work, LSEs would need to report their bundled contracts by technology type because the implicit energy value is significantly different among the technology types. That is, a single-price contract using wind technology should

[1] Informal Comments of The Alliance for Retail Energy Markets and the Direct Access Customer Coalition on PCIA Working Group #1 Straw Proposal (Workshop #1), page 2.

not be used to benchmark a single-price contract using solar, let alone geothermal or small hydro. Different renewable generation technologies have such different energy delivery profiles, such that the "implicit" energy values in the contracts could be very different. Unless the reporting and creation of the benchmark is technology specific, the benchmark ends up with apples-to-oranges comparisons, which defeats the purpose of the "bundled-price" benchmark.

- Once the benchmarks are established for each technology type, the IOU Total Portfolio would need to be broken down into volumes that are coming from bundled contracts by technology type so that the bundled benchmarks could be applied appropriately.
- Then if the bundled contract includes both RA and RPS, there would need to separate reporting of the bundled price by technology type for those contracts, and similar disaggregation of the IOUs Total Portfolio.
- Finally, it is not clear that the TURN suggestion comports with D.18-10-019 in that it creates multiple new benchmarks, while D.18-10-019 only specifies the creation of RA and RPS adders.

Theoretically, the only way to properly back out the RPS value from a single-price contract would to gather actual, or forecast, hourly CAISO power prices, proxy hourly power delivery profiles for the renewable resource that each project represents, the amount and timing of the NQC that the project provides, and the RA price/type for that resource. If the CPUC and Energy Division does not have the appetite for conducting this type of calculation on an annual basis for multiple contracts so as to include them in the benchmark, then some simplification, such as that proposed by the Working Group #1 Chairs, must be found.

III. COMMENTS ON PROPOSED RA BENCHMARK CHANGES

First, AReM/DACC note the updated straw proposal's explicit differentiation of the three types of RA (local, flex and system). AReM/DACC find the proposed treatment—system and flex RA adders based on state-wide data and identical for the three IOUs and local based on TAC area—to be appropriate. Second, AReM/DACC appreciate the updated straw proposal addressing how the multi-year local RA contracting requirement can be integrated into the local RA market price benchmark adder. The proposal laid out on slides 14 and 15 appears to address the multi-year forward issue, although because it would base the local RA benchmark on data beyond year "n+1", a petition to modify Decision 18-10-019 may be needed.

IV. CONCLUSION

AReM/DACC thank the Working Group co-chairs for their hard work and look forward to working through these and undoubtedly other issues.

Respectfully submitted,

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DIRECT ACCESS CUSTOMER COALITION

April 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	**Rulemaking 17-06-026** **(Filed June 29, 2017)**

INFORMAL COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON WORKING GROUP ONE WORKSHOP #2 HELD MARCH 26, 2019

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April 2, 2019

CLECA[1] commends the co-leads for their management of second workshop and their continued efforts in leading this working group. We appreciate this opportunity to offer informal comments on workshop #2; our brief informal comments make the following key points:

- Use of the CAISO's backstop procurement, specifically, the Capacity Procurement Mechanism (CPM) in the RA Adder contravenes D. 18-10-019;
- TURN's proposal on including fixed-price RPS PPAs in the RPS MPB warrants further development and discussion;
- Unsold RA Volumes' de minimis value should be between 5-10% of the contract price (instead of a zero value) and unsold RA should not be valued at the benchmark.

CLECA organizes these points by the focus questions for non-consensus items on slides 54-55 of the workshop #2 presentation. For questions 1 and 3, CLECA supports the proposed schedule and the proposal to account for multi-year procurement of Local RA in the MPB.

5. Should CPM Backstop Procurement from the CAISO Be Included in Calculation of the RA Adder?

No; the CPM Backstop procurement from the CAISO should not be included in the calculation of the RA Adder because the Commission clearly rejected this proposal in D. 18-10-019. CLECA's counsel attended Workshop #2, and like Workshop #1, there was little to no

[1] CLECA is an organization of large industrial electric customers of Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE); the member companies are in the steel, cement, industrial gas, mining, pipeline, cold storage, and beverage industries and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite generation. CLECA has been active in Commission proceedings since the early-to-mid 1980s and strives for even-handed treatment of all customers.

actual debate or discussion of this item at the workshop; participants were encouraged to state their positions in these informal comments. As CLECA's position has not changed, CLECA reiterates many of its prior points made in the first round of informal comments.

CLECA continues to oppose use of the CPM price in the RA Adder; this opposition is based on the clear language in D. 18-10-019, which states:

> we adopt new benchmarks for the RPS Adder and the RA Adder in order to improve the initial accuracy of the PCIA that will be in effect each year. We also adopt an annual true-up requirement to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented."[2]

As CLECA noted previously, specifically regarding the RA Adder, the Commission directed use of TURN's RA Adder:

> we adopt TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n). A zero or de minimis price shall be assigned for capacity expected to remain unsold.[3]

TURN's RA Adder did not include use of the CPM. Moreover, in response to CalCCA's proposal to use the CPM to benchmark capacity, CLECA's testimony in R. 17-06-026 explained why the CPM price is not appropriate for use in the RA Adder or for benchmarking capacity costs:

> Reliability Must Run and CPM contracts are used for backstop when resources that are not contracted for RA are determined through power flow studies to be needed for reliability. Market prices for capacity have been dampened by the existence of excess capacity procured for policy reasons other than capacity value, such as RPS procurement.
>
> CalCCA proposes to use the soft offer cap for the CAISO's backstop CPM that is used in cases of RA resource deficiency (most recently in local capacity areas or subareas), exceptional dispatch (e.g. for a transmission emergency), or for significant events (unexpected conditions like the shut-down of the San Onofre Nuclear Generating Stations (SONGS)). It can be used for as little as 30 days or as long as a year. This is the

[2] D. 18-10-019, at 62.
[3] D. 18-10-019, at 73.

> going forward fixed cost of a 550 MW combined cycle plant with duct firing plus a 20% adder. It is currently $75.68/kW-year. The CPM is only used in the case of a deficiency, which is for the CAISO occasioned by a reliability concern. Thus, by its very nature, if a resource is procured through the CPM, it is not surplus capacity. Furthermore, the soft offer cap has become something of a floor, since recent CPM procurement has occurred at values very close to the soft cap. For these reasons, I do not support its use as proposed by CalCCA as a value for surplus capacity, nor do I support CalCCA's determination of surplus capacity.[4]

D. 18-10-019 is clear that the RA Adder is to be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions"; this does not include use of a CAISO administratively-determined price, e.g., the CPM. If parties want to change the RA Adder to include use of the CPM, they should file a petition for modification of D. 18-10-019; it is not appropriate to attempt to re-litigate this issue in a working group.

6. Should local resources transacted for System RA needs be included in the Local RA MPB.

No. While CLECA understands that the scenario posited by this question, where a Local RA resources is procured as a System RA resource and not shown as a Local RA resource in the supply plan, is possible, it seems improbable to be a widely-spread occurrence. If a resource is bought and sold to meet System RA needs, it should be included in the System RA MPB, not the Local RA MPB. Only those resources transacted to meet Local RA needs should be reflected in the Local RA MPB. Confidentiality concerns should be addressed by aggregating resources.

[4] Ex. CLECA-1 in R. 17-06-026, Testimony of Dr. Barbara R. Barkovich, at 12.

7. **Acknowledging the challenges of doing so, should the co-leads continue to work at developing a methodology to include fixed-price PPAs in the RPS MPB?**

Yes, because as was pointed out in the workshop #2, most (65%) of the RPS procurement will need to be done through long-term contracts, and these transactions should not be excluded from the determination of the RPS benchmark. TURN's proposal offers a starting place, and, even though complicated and challenging, CLECA supports continued discussion and development of a methodology to ensure RPS market transactions are appropriately included in the RPS benchmark.

8. **Comment on the strawman proposal to forecast amounts/volumes of unsold RA in each IOUs ERRA Forecast proceeding by comparing to the previous year's unsold amount**

CLECA supports the strawman proposal given its description at workshop #2.

9. **For capacity expected to remain unsold in the PCIA forecast, what is an appropriate de minimis value? If proposing a value other than zero, please explain the methodology for arriving at such value.**

An appropriate de minimis value for capacity expected to remain unsold is 5-10% of the contract price. [5] It would not be good policy for a zero value to be assigned to resources whose procurement was previously authorized by the Commission and approved as meeting the "just and reasonable" standard. There is no methodology for arriving at this 5-10% value range; it is offered as a practical solution. Moreover, using a 5-10% contract price valuation should not significantly distort the RA Adder (unlike some proposals to value some unsold quantities at the RA benchmark based on proposed criteria for not counting them as unsold).[6] While CLECA

[5] D. 18-10-019, at 73, 121 (directing that "A zero or de minimis price shall be assigned for capacity expected to remain unsold.").
[6] See slide 38 of Workshop #2 presentation.

understands and shares CalCCA's desire to improve transparency and discipline of utility offerings to sell RA resources, we see that as an appropriate topic for portfolio optimization in Working Group 3. In the meantime, we do not support distorting the RA MPB by assigning a higher than de minimis value to unsold RA.

10. For capacity that remains unsold, what is an appropriate value to be used in the true-up? If proposing a value other than zero, please explain the methodology for arriving at such value.

See our response to question 9; perhaps for the true-up, the lower end of the 5-10% range could be used to minimize the de minimis impact this valuation would have.

CLECA looks forward to continued engagement in Working Group One.

Respectfully submitted,

Buchalter, A Professional Corporation

By:

Nora Sheriff

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April 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COMMENTS OF THE COALITION OF CALIFORNIA UTILITY EMPLOYEES ON PCIA PHASE 2 – WORKING GROUP ONE WORKSHOP #2

April 2, 2019

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

**COMMENTS OF THE COALITION OF CALIFORNIA UTILITY EMPLOYEES ON
PCIA PHASE 2 – WORKING GROUP ONE WORKSHOP #2**

I. INTRODUCTION

The Coalition of California Utility Employees (CUE) appreciates the opportunity to provide comments on the March 26, 2019 PCIA Phase 2 Working Group One: Benchmark True-Up and Other Benchmarking Issues Workshop #2. CUE also appreciates the responses by Working Group One to comments made on Workshop #1 in Workshop #2. CUE has comments on several issues discussed in Workshop #2. CUE's comments follow the format for focus questions provided by Working Group One.

II. PROCEDURAL

1. **What are your thoughts on number of workshops (3) and proposed schedule to address items Scoping Memo issues 8-12?**

The number and timing of workshops to address Scoping Memo issues 8-12 is reasonable.

III. NUMBER AND TYPE OF MPBs

2. For aggregating Local RA, what is the appropriate number of transactions, and/or LSEs that should be represented before aggregating the resulting MPB to preserve confidentiality and/or market power?

CUE does not have comments on this issue at this time but reserves the right to comment in the future. The answer to this question may depend on the resolution of question 6, whether to include local resources transacted for System RA in the Local RA MPB.

IV. Data Inputs to RA and RPS Adders

3. Please provide comments on proposal to account for multi-year procurement of Local RA in the MPB.

CUE understands the proposal to use n-1 year results for 2020, n-2 results for 2021, and n-2 and n-3 results after that. Based on this understanding, CUE finds the proposal to be reasonable.

4. Should contract extensions/amendments be used to calculate the MPB. If so, please define a framework for which transaction should be included.

The answer to this question depends on the nature of the contract extension or amendment. In the case of a contract extension, if the previous years of the contract were used to calculate the MPB, then the contract extension (if exercised) should be included in the MPB. For example, consider a contract that, for the first two years, contracted for 12 months of 100 MW of RA capacity at $1.00/kW-month. For the third year, the buyer has the choice (the option) to extend the contract for a third year at a price pre-set in the contract, or the buyer can choose not to extend. If the first two years are included in the MPB and the option to extend is exercised, then it is reasonable to include the third year because the buyer has an option to extend or not embedded in the contract. The prices for the first two years will include a premium to account for the buyer's option to extend, while the extension price might be lower than prevailing market prices. Therefore, it is unreasonable to include the first two years in the MPB with higher than market prices, but then exclude the exercised extension.

Alternatively, CUE proposes to exclude those contracts with extension/option provisions when calculating the MPB.

5. **Should CPM backstop procurement from the CAISO be included in calculation of the RA Adder? Why or why not?**

CPM backstop procurement from the CAISO should not be included in the calculation of the RA Adder. These transactions are out-of-market transactions, not market-based purchases. D.18-10-019 clearly excludes the use of CPM in the calculation of the RA Adder. CUE agrees with CLECA that "the working group process should not be subverted into re-litigation of issues already decided by the Commission."

6. **Should local resources transacted for System RA needs be included in the Local RA MPB?**

Use of local resources transacted for System RA needs in the Local RA MPB may help address the confidentiality and market power concerns referenced in question 2. Moreover, including these local resources could better reflect market conditions for Local RA.

7. **Acknowledging the challenges of doing so, should the co-leads continue to work at developing a methodology to include fixed-price PPAs in the RPS MPB?**

CUE supports continued work to develop a methodology to include fixed-price PPAs in the RPS MPB. After all, the overwhelming majority of all RPS purchases are through long-term contracts. Excluding them would misrepresent the market. CUE recognizes that there are technical challenges that may make including fixed price PPAs difficult but thinks the issue should be explored in more detail. CUE agrees with TURN that PPAs involving mandatory procurement, such as forest biomass, should be excluded from the MPB.

V. UNSOLD RA

8. Please comment on the strawman proposal to forecast amounts / volumes of unsold RA in each IOUs ERRA Forecast Proceeding by comparing to the previous year's unsold amount.

Absent new information, CUE believes this approach is reasonable.

9. For capacity expected to remain unsold in the PCIA forecast, what is an appropriate de minimis value? If proposing a value other than zero, please explain the methodology for arriving at such value.

For capacity expected to remain unsold in the PCIA forecast, the appropriate value is zero, the same as the value used for the true-up.

10. For capacity that remains unsold, what is an appropriate value to be used in the true-up? If proposing a value other than zero, please explain methodology for arriving at such value.

For capacity that remains unsold, the appropriate value to use in the true-up is zero because the market value of such capacity is zero. If the IOUs have attempted to sell the capacity but found no buyers, then it has no value in the market. Some parties recommend placing conditions or requirements on what constitutes a legitimate attempt to sell capacity. Working Group One is not the appropriate forum to consider this issue. Rather, Working Group Three (portfolio optimization) is the appropriate forum to consider conditions for offers to sell capacity.

Dated: April 2, 2019

Respectfully submitted,

/s/

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting a Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMERCIAL ENERGY OF CALIFORNIA'S INFORMAL COMMENTS ON WORKING GROUP ONE UPDATED PROPOSAL

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Dated: April 2, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting a Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMERCIAL ENERGY OF CALIFORNIA'S INFORMAL COMMENTS ON WORKING GROUP ONE UPDATED PROPOSAL

In accordance with the agreed-upon procedures discussed at the Working Group 1 workshops held on March 1 and 26, 2019, Commercial Energy of California provides its informal comments on Working Group 1's updated proposal, presented at the March 26 workshop.

Commercial Energy does not have any comments at this time on the proposed schedule and mechanism for developing RPS and RA adders and incorporating them into the utilities ERRA filings. Commercial Energy reserves the right to make additional substantive comments on these issues in the future.

1. Confidentiality of Load Serving Entity Data Responses

In its comments on the Working Group's initial proposal, Commercial Energy expressed concern that the contract information that would be provided to the Commission pursuant to the proposal is highly confidential and extremely commercially sensitive, particularly to ESPs. Commercial Energy also noted that, because the Commission does not have direct jurisdiction over ESP rates, it is important that any ESP contract information provided to

Commission staff be provided under procedures designed to preserve the LSE's confidential trade secrets and competitive procurement pricing information. To ensure this protection, Commercial Energy proposed that: (1) all data responses provided to the Commission under the procedure adopted to develop RA and RPS adders be provided directly to Energy Division and be accompanied by a declaration of an officer of the entity attesting to the information's confidential nature; (2) the data responses be provided to the designated Energy Division recipient and no other persons; and (3) the confidential LSE data held by Energy Division be destroyed once the adders are calculated by Energy Division. Other parties expressed similar concerns regarding confidentiality of LSE contract information.

The updated proposal presented at the March 26, 2019 workshop provided two responses to the parties' concerns about confidentiality of contract information: (1) that the recent ruling from ALJ Atamturk confirmed that all data provided by LSEs will be protected under D.06-06-066; and (2) that destruction of data after a three-year period would prevent audits of past adder calculations.[1]

Commercial Energy notes that nothing in D.06-06-066 prevents the Commission from fashioning additional protocols to protect the substantial amount of highly sensitive contract information that Energy Division will begin amassing, likely on a quarterly basis. The general protections in D.06-06-066 do not leave LSEs' information totally exposed, but neither does that decision provide protection measures tailored to this unique situation. The additional protections recommended by Commercial Energy should be adopted.

Commercial Energy also notes that, if the parties are auditing the adders after three years have passed, there will never be any certainty in the market as to resource prices. But

[1] Updated Presentation, slide 40.

if auditability of the adders after three years is a legitimate concern, the Commission should direct that LSEs preserve the contract data themselves. Preserving the data as it was provided to Energy Division, for the period of time directed by the Commission, should not present serious problems. Commercial Energy does not foresee significant problems with preserving the data and maintaining its integrity.

Commercial Energy understands that this issue will likely be preserved for "briefing," along with any other issues the parties are unable to agree on. Commercial Energy supports this procedural step.

Respectfully submitted April 2, 2019, at San Francisco, California.

GOODIN, MACBRIDE,
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By *<u>/s/ Michael B. Day</u>*
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THE PUBLIC ADVOCATES OFFICE'S INFORMAL COMMENTS

ON THE ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDERING ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT (R.17-06-026)

PHASE 2,WORKING GROUP 1: BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

Submitted by	**Organization**	**Date Submitted**
Mea Halperin Senior Analyst Phone: (415) 703-1368 Email: Mea.Halperin@cpuc.ca.gov Nicole McDonald Analyst Phone: (415) 703-5463 Email: Nicole.McDonald@cpuc.ca.gov Public Advocates Office California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102	Public Advocates Office – California Public Utilities Commission	April 2, 2019

The Public Advocates Office submits the following informal comments in response to the March 26, 2019 Second Workshop for Working Group One: Benchmark True-Up and Other Benchmarking Issues.

Question 2: For aggregating Local RA, what is the appropriate number of transactions, and/or LSEs that should be represented before aggregating the resulting MPB to preserve confidentiality and/or market power?

The Public Advocates Office supports aggregating the local resource adequacy (RA) Adder using RA sales and purchases by local area rather than by transmission access charge (TAC) areas because price information at the local area level is more readily available, more granular, and therefore more accurate, than at the TAC level. Thus, using the local area would provide a more accurate benchmark. Parties' opposition to aggregating based on the local area because of concerns about preserving confidentiality and market power is not justified because information on capacity prices by local area is already publicly available in *The 2017 Resource Adequacy Report* released by the Commission in August 2018.[1] The Public Advocates Office supports the use of this public data on local area capacity prices for aggregating local RA as it provides a greater level of granularity than TAC areas and is readily available.

Question 5: Should CPM backstop procurement from the CAISO be included in calculation of the RA adder? Why/why not?

The Public Advocates Office supports CLECA and PG&E in not including capacity procurement mechanism (CPM) backstop procurement from the California Independent System Operator (CAISO) in the RA adder calculation. CAISO currently recovers and allocates costs and revenues associated with CPM backstop procurement from LSEs through its settlement process. Therefore, there is no need to include it in the RA adder calculation.

According to the PCIA Decision (D.)18-10-019, "The RA adder shall be calculated using reported purchase and sales prices from IOU, CCA [community choice aggregator], and Electric Service Provider (ESP) transactions made during (year n-1) for deliveries in (year n)."[2] The CPM backstop procurement process is not based on transactions in the RA market, and therefore is not an appropriate component of the RA adder. PG&E noted in the working group presentation that "any actual CPM revenues of PCIA-eligible resources are credited to PABA [portfolio allocation balancing account],"[3] so the revenues received through the backstop procurement process will be a component of the ultimate PCIA true-up.

[1] California Public Utilities Commission, *The 2017 Resource Adequacy Report*, August 2018, p. 28.

[2] D.18-10-019, Ordering Paragraph 1c, pp. 159-160.

[3] PCIA Phase 2: Working Group One, Workshop #2, Presentation, p. 30.

Question 7: Acknowledging the challenges of doing so, should the co-leads continue to work at developing a methodology to include fixed-price PPAs in the RPS MPB?

The Public Advocates Office supports including fixed- price power purchase agreements (PPAs) in the renewable portfolio standard (RPS) market price benchmark (MPB). [4] TURN is correct that "the exclusion of all long-term fixed price PPAs from the MPB would skew the calculation of above-market costs by limiting the "market" to short term transactions that will represent a declining share of new renewable energy procurement."[5] This is particularly true in light of long-term contracting requirements for the RPS in 2021 and beyond necessitating that 65% of a retail seller's[6] renewable procurement requirement must be procured through contracts with a term of ten years or more.[7] Without the fixed-price contracts, the MPB would imply that renewables are always trading at or above a premium price, potentially leading to future inflated

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[4] Comments of The Utility Reform Network (TURN) on The Phase 2 Working Group #1 Workshop, March 8, 2019, pp. 1-4; Comments of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition (AReM/DACC) on PCIA Working Group #1 Straw Proposal, March 8, 2019, pp. 2-3; Comments of the Coalition of California Utility Employees (CUE) on PCIA Phase 2 - Working Group One Workshop #1, March 8, 2019, p. 2.

[5] TURN informal comments on PCIA Phase 2 - Working Group #1 Workshop #1, p. 4.

[6] Public Utilities Code Section 399.12 (j) "Retail seller" means an entity engaged in the retail sale of electricity to end-use customers located within the state, including any of the following:

(1) An electrical corporation, as defined in Section 218.

(2) A community choice aggregator. A community choice aggregator shall participate in the renewable portfolio standard program subject to the same terms and conditions applicable to an electrical corporation.

(3) An electric service provider, as defined in Section 218.3. The electric service provider shall be subject to the same terms and conditions applicable to an electrical corporation pursuant to this article. This paragraph does not impair a contract entered into between an electric service provider and a retail customer prior to the suspension of direct access by the commission pursuant to Section 80110 of the Water Code.

(4) "Retail seller" does not include any of the following:

(A) A corporation or person employing cogeneration technology or producing electricity consistent with subdivision (b) of Section 218.

(B) The Department of Water Resources acting in its capacity pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(C) A local publicly owned electric utility.

(k) "WECC" means the Western Electricity Coordinating Council of the North American Electric Reliability Corporation, or a successor to the corporation.

[7] Under the current RPS, in order to count procurement from short-term renewable contracts towards RPS requirements, a retail seller must also procure long-term renewable contracts at a quantity of at least 0.25% of its total retail sales requirement from the previous RPS compliance period. For the current rules, see D.12-06-038, Ordering Paragraph 15, p. 98. For the 2021 requirements, see D.17-06-026, pp. 9-10.

renewable contract prices. Including fixed-priced PPAs is challenging and time-consuming because of the complexity of the calculations, the difference in units between index-plus and fixed-price contracts, and the significant lag between execution and online date results in stale prices.[8] However, the co-leads together with stakeholders should at least consider TURN's alternative approach[9] or propose another method that accounts for fixed-price contracts in the RPS MPB.

Question 9: For capacity expected to remain unsold in the PCIA forecast, what is an appropriate de minimis value? If proposing a value other than zero, please explain methodology.

The Public Advocates Office supports CalCCA's proposal for assigning a zero or de minimis value to unsold RA: "Capacity that remains unsold due to the IOU's rejection of bids below the IOU's price floor will be valued at the price floor as the de minimis price."[10] If an IOU chooses not to sell its RA capacity because it determines that there is a minimum value or a floor price for holding the RA capacity then this presumes a greater-than-zero value for the unsold capacity. Outside of this condition, unsold RA capacity should be valued at zero dollars.

There is no intrinsic value for the IOUs' RA capacity that goes unsold, but to assign a higher de minimis value would imply that bundled customers would have to pay for some unseen benefit from unsold RA. Generally, the higher the value for unsold RA, the lower the PCIA will be for departing load customers. It is important to accurately account for the different types of RA in order to ensure a fair and accurate PCIA charge. Therefore, unsold RA capacity should be valued at zero dollars except when IOUs elect not to sell their RA capacity for less than the floor price.

However, the Public Advocates Office requests that PG&E clarify what determines RA that is "reserved" by the IOUs.

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[8] PCIA Phase 2: Working Group One, Benchmark True-Up and Other Benchmarking Issues, Workshop #2 Presentation, March 26, 2019, slide 33.

[9] TURN, Concerns about proposed renewable benchmark presentation, March 26, 2019, slide 3.

[10] PCIA Phase 2: Working Group One, Workshop #2, Presentation, p. 37.

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Via E-Mail

April 2, 2019

To: All Parties in R.17-06-026 (PCIA)

Re: Informal Comments of Shell Energy North America (US), L.P. on Updated PCIA Market Price Benchmark True-Up Proposal

In accordance with the schedule established by the parties in this PCIA working group process, Shell Energy submits its informal comments on the updated PCIA market price benchmark ("MPB") "true-up" proposal that was discussed at the March 26, 2019 workshop. Shell Energy's comments are as follows:

First, LSEs should not be required to submit data on RA and RPS transactions on a quarterly basis. No legitimate reason exists to impose this reporting burden on LSEs, particularly because the PCIA is determined on an annual basis. LSEs should not be required to provide quarterly submissions "to allow the Energy Division time for a data clean up." As noted in the true-up proposal (Slide 9), the Energy Division will publish two sets of RA and RPS adders by November 1 of each year: a "forecast" of RA/RPS adders to be included in the MPB for the delivery year; and a "final" RA/RPS adder used to true-up the entries for products used by the IOUs in the delivery year. In addition to the reporting required in D.18-10-019, LSEs should not be required to provide an update of RA and RPS prices more than once per year. With one update, the Energy Division will have sufficient information to develop both the forecast data and the actual data needed to reflect LSEs' RA and RPS prices in the MPB and PCIA.

Second, LSEs should not be required to submit RA and RPS price data to the Energy Division for the purpose of calculating the true-up. Rather, all LSEs should be directed to provide all RA and RPS prices to a published index developer (e.g., ICE) so that an independent, unbiased index of actual prices can be established. If all LSEs participate in this index (or trading platform/electronic bulletin board), the index will reflect a transparent, robust average of LSEs' RA and RPS prices. This transparent index will also present a liquid platform for trading RA and RPS products, making the market more open and competitive.

Third, if an "index" or EBB is used for submission of LSEs' RA and RPS prices, LSEs should be required to include, in their submissions, all transactions that include RA and/or RPS products. Limiting the submission of LSE transactions to RA-only transactions, or "market-based PCC-1 'index-plus'" transactions, will miss resources and produce an inaccurate representation of a "market" price for RA and/or RPS products. To the extent that a multi-product PPA (or utility-owned generation) includes an RA and/or RPS component, the LSE should be required to report an RA price and/or an RPS price for the transaction.

Shell Energy looks forward to discussing the foregoing issues at the next workshop.

Best regards,

John W. Leslie
Dentons US, LLP
Attorneys for Shell Energy North America (US), L.P.

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EXHIBIT F

Power Charge Indifference Adjustment (R.17-06-026)

Phase 2: Benchmark True-Up and Other Benchmarking Issues

Working Group Progress Report

to the California Public Utilities Commission

California Community Choice Association
Pacific Gas and Electric Company
March 20, 2019

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Introduction and Background

Procedural Background

On October 11, 2018 the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 18-10-019 modifying the Power Charge Indifference Adjustment (PCIA) Methodology. D. 18-10-019 determined that a second phase of the proceeding would be opened in order to establish a "working group" process to enable parties to further develop proposals for consideration by the Commission. On February 1, 2019 the Commission issued a scoping memo in Rulemaking (R.) 17-07-026 directing the parties to convene three working groups to further develop PCIA-related proposals for consideration by the Commission ("Phase 2 Scoping Memo").[1]

The Phase 2 Scoping Memo designated Pacific Gas and Electric Company ("PG&E") and California Community Choice Association ("CalCCA") as Co-Chairs of Working Group One: Benchmark True-Up and Other Benchmarking Issues ("Working Group One"). The Commission anticipates resolving Working Group One issues "in time to be implemented in the Joint Utilities respective 2020 ERRA Forecast Updates in early November 2019" and the Phase 2 Scoping Memo established a procedural schedule to do so, with a proposed decision on brown power, renewable portfolio standard, and resource adequacy true-up issues issued by September 2019. [2] The Phase 2 Scoping Memo also established a procedural schedule requiring Working Group one to address load forecasting, billing determinants, and bill presentation issues for a proposed decision in fall 2019.[3] The Commission intends to issue a proposed decision on the Working Group One issues one through seven by September 2019 and a second proposed decision for issues eight through twelve later in Fall 2019.

PG&E and Cal-CCA as co-chairs of Working Group One, led by Mr. Joe Lawlor and Mr. Todd Edmister respectively,[4] are responsible for a number of tasks, described further

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[1] Phase 2 Scoping Memo and Ruling of Assigned Commissioner (R. 17-06-026) [hereinafter Phase 2 Scoping Memo] at page 3.
[2] Phase 2 Scoping Memo at pages 3 and 7.
[3] Id.
[4] Other CalCCA representatives included Ann Springgate and Evelyn Kahl as attorneys for CalCCA and Sam Kang as CalCCA's consultant. Also included in some working group conversations were

below, including scheduling and leading meetings, and serving reports to the Commission according to Scoping Memo.[5] This report satisfied PG&E's and CalCCA's requirement to serve a first progress report of Working Group One's activities.[6]

Working Group One Scope

Issues assigned to working group in scoping memo (items 1-12)

1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true-up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?
3. Should the true-up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true-up process be addressed?
4. Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annual the RA adder and the RPS adder of the Market Price Benchmark?
5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?
6. How should the Commission clarify/define forecasting amounts of unsold RA?
7. D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the [Market Price

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representatives from Peninsula Clean Energy, Silicon Valley Clean Energy, SFCleanPower, and Marin Clean Energy.

[5] Phase 2 Scoping Memo at p. 10.

[6] Phase 2 Scoping Memo at p.7.

Benchmark (MPB)].” Are further parameters needed to define a *de minimis* price, and if so, what are these parameters?

8. Which methodologies, probabilistic or scenario-based, should the Commission adopt to forecast departing load?
9. What are the barriers for the IOUs to obtain the information they need to adequately forecast future CCA departing load and mitigate future forecasting inaccuracies, and how can they overcome those barriers?
10. What mechanisms would help minimize future deviations between announced and actual load departure dates, thereby improving the fidelity of departing load forecasts?
11. Should the Commission clarify the definition of billing determinants and their proper usage for calculating the PCIA, and if so, how?
12. Should the Commission require any changes in the presentation of the PCIA in tariffs and on customer bills, and if so, what should those changes be?

Working Group One Responsibilities

As co-chairs of Working Group One, PG&E and CalCCA are obligated to perform the following tasks:

1. Scheduling the Working Group’s meetings, along with handling associated logistics;
    a. Pursuant to the Rules of Practice and Procedure 8.1(b)(3), meeting times, locations, and online access information, if applicable, should be noticed to the entire service list.
    b. Service list notification should include language to inform the service list that decisionmakers may be present at the meeting
2. Leading each of the Working Group’s meetings; and

3. Ensuring that the final report, or reports, of each Working Group is finalized and subsequently filed and served at the Commission according to the schedule or that working group.[7]

Co-chairs are also responsible for writing and serving two progress reports and two final reports. Working Group participants are directed by the Phase 2 Scoping Memo "to develop more detailed agreements on how they will approach their responsibilities…to ensure that its work proceeds openly and efficiently".[8]

Summary of Co-Chair Activities

Working Group One Proposal Development

PG&E and CalCCA agreed to weekly conference calls to discuss proposal development status and areas of alignment, scheduling extended in-person meetings as needed to finalize the proposal for the first meeting and progress report. PG&E and CalCCA representatives met eight times between January 29, 2019 and March 1, 2019 to develop proposals and address Issues 1-7. Five sessions were via teleconference and lasted .5 hours each; three sessions were in-person at PG&E's San Francisco General Office and lasted 2 hours each. Meetings were collaborative in nature with each party bringing forth proposals and concepts vetted by Investor Owned Utility (IOU) and Community Choice Aggregation (CCA) constituents. To prepare for the Initial working group meeting, much of proposal development was completed offline and meetings were used to review work completed. To ensure incorporation of stakeholder feedback, the IOUs and CCAs met with their constituents separately to discuss proposal drafts. PG&E and CalCCA then met to determine proposals' area of alignment and consolidate where possible.

By the March 1 meeting, PG&E and CalCCA developed a straw proposal that established methodology, data reporting, and timing necessary to produce RA and RPS adders for the MPB.

[7] Phase 2 Scoping Memo at 10.
[8] Id.

Initial Working Group One Meeting

Notification of Initial Meeting of Working Group One

PG&E notified the R. 17-06-026 service list that the Initial Meeting of Working Group One would be held on March 1, 2019 on February 22, 2019. The notification included a web conference option for parties unable to attend in-person. CalCCA provided Initial Meeting Materials to the R.17-06-026 service list on February 28.

Meeting Description

The Initial Meeting took place on March 1, 2019 from 10:00 AM to 12:00 PM in the Courtyard Room of the CPUC San Francisco building. Thirty-nine parties attended the meeting in-person. A web conference option was provided for parties attending remotely. A list of attendees is attached to this report as Appendix B, along with information on the number of parties that dialed in, and the parties that use the web conference option.

The presentation given at the meeting is attached to this report as Appendix A. Mr. Lawlor of PG&E presented pages 3-8, 29-33, introducing and concluding the meeting. Mr. Klingler of PG&E presented page 9, the alignment of the benchmark process with the ERRA Forecast calendar. Mr. Edmister, representing CalCCA, presented pages 10-15, the material portion of the straw proposal. Mr. Kikuyama representing PG&E presented pages 16-21, which discussed potential data request template changes to improve the accuracy of the RA and RPS adders. Ms. Barry representing PG&E presented pages 22-27, an overview of PG&E's proposed Portfolio Allocation Balancing Account (PABA) structure.

Parties were notified at the meeting that written comments on the presented proposal would be accepted through March 8, 2019. CalCCA and PG&E requested that the comments be served via the service list so all parties would have the opportunity to stay informed on the proceeding and Working Group One activities.

Straw Proposal Presentation

Detail of Straw Proposal

As noted above, for the slide deck with the Straw Proposal, see Appendix A. The following section describes how the Straw Proposal presented at the Initial Meeting addresses Issues 1-7 of Working Group One:

1. Issue 1: Which mechanism(s), procedural and/or methodological, should the Commission adopt to true-up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
    a. Energy Division (ED) issues data request in September for submittal by all Load Serving Entities (LSEs)to which LSEs must respond by approximately October 15.
    b. By November 1 of each year, ED will publish two adders for RA and RPS:
        i. Forecast: to be used in setting the PCIA rates for year N
        ii. Final: to be used in truing up the imputed RA/RPS PABA entries for products (i.e., those products used by the IOUs for compliance)
    c. RA adder: includes market-based RA-only sales and purchases from IOU, CCA, and ESP transactions
    d. RPS adder: limited to market-based PCC1 "index-plus" sales and purchases from IOU, CCA, and ESP transactions
    e. IOUs use forecast RA and RPS adders to establish PCIA rates and include in year N ERRA Forecast Update, filed November of year N-1
    f. IOUs true-up balancing account entries for year N
        i. All recorded transactions of RA and RPS, at actual transacted value and quantities; and
        ii. Final imputed RA/REC adders using RA and RPS adders
    g. Any over- or under-collection is recovered in subsequent year's rate

2. Issue 2: Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?
    a. For forecast year 2020 and beyond, Energy Division will issue a data request to all LSEs in September with a response deadline of approximately October 15. This data request will capture purchases and sales from Q4 of year N-2 and Q1-3 of year N-1 for delivery in year N. ED will then calculate the RA and RPS forecast and final adders for use in ERRA Forecast Proceeding.
3. Issue 3: Should the true-up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true-up process be addressed?
    a. The true-up process should take place as part of the ERRA Forecast proceedings. Any over- or under-collections are rolled into the following year's PCIA rate, which are filed within the ERRA Forecast Update.
4. Issue 4: Which mechanism(s), procedural and/or methodological, should the Commission adopt to develop annually the RA adder and the RPS adder of the Market Price Benchmark?
    a. See above.
5. Issue 5: Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?
    a. Much of the data reported by the categories below is already shared with the ED as part of RA and RPS data requests. Minor updates to the existing templates were proposed to capture the appropriate data points for inclusion in the benchmark. Relying upon the existing data response template currently issued by the ED may increase reporting efficiency.
    b. The data necessary to accurately calculate the RA adder is as follows: contract ID between parties, month and year of delivery, resource scheduling ID, resource name, CAISO zone for unspecified resources, buyer, seller,

system capacity under contract, local capacity under contract, price, contract execution date, type of generation, combined heat and power contract.

   c. The data necessary to accurately calculate the RPS adder is as follows: contract ID, seller name, buyer name, project name, CAISO resource ID, contract execution date, month and year of delivery, volume, contract length, expected PCC classification, contract price (pre-TOD and TOD adjusted).

6. Issue 6: How should the Commission clarify/define forecasting amounts of unsold RA?
   a. Forecasting unsold RA quantities remains an outstanding issue.
7. Issue 7: D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a *de minimis* price, and if so, what are these parameters?
   a. De minimis price determination for unsold RA remains an outstanding issue.

Open Issues

Working Group One Co-Chairs are still discussing the following issues:

Use of backstop procurement in the RA adder

Co-chairs do not agree on the use of backstop procurement in the RA adder calculation. CalCCA supports including CAISO Capacity Procurement Mechanism (CPM) transactions in the RA adder. PG&E does not support the inclusion of CPM transactions on the basis that these are out of market transactions rather than market-based purchases and sales of RA to inform the adder as generally described by D.18-10-019.

Transitional issues

Working Group One Co-Chairs continue to discuss an implementation timeline for 2019. It is yet to be determined how the true-up for 2019 will be executed. Additionally, a transitional framework will need to be developed in the event that the CPUC decisions are delayed beyond the end of 2019.

Implementation of the RA Adder to reflect the three types of RA capacity

Working Group One Co-Chairs are considering how to reflect system, local, and flexible capacity in the RA adder.

Addressing unsold RA volumes

Working Group One Co-Chairs are considering how a zero or de minimis price should be assigned for RA capacity expected to remain unsold for the purpose of calculating the RA adder to the MBP.

Working Group One Co-Chairs are also discussing how to address issues 8-12.

Verbal Comments Offered in Response to the Straw Proposal

A number of parties offered substantive verbal comments on the straw proposal for items 1-7 at the Initial Meeting. Themes included data used to calculate the MPB, potential gaming issues, MPB calculation timeframe, and whether changes in RA requirements are impactful to RA MBPs. The straw proposal relies on PCC1 "index-plus" prices to obtain an RPS adder, and concern was voiced that limiting the benchmark to this data set may overlook a portion of the market. Other comments concerned potential gaming. Other issues brought up were the timeframes for calculating and publishing the MPB within the proposed two weeks of receiving the data. Some parties suggested a more lenient timeline as this would be a pilot year.

Follow-Ups

In response to ED's concerns raised at the March 1 meeting regarding the data reporting and benchmark calculation portion of the straw proposal, representatives from PG&E and CalCCA met with Energy Division on March 7, 2019. Mr. Lawlor and Mr. Edmister noted at the meeting that the working group hadn't yet coordinated the timing elements with ED but committed to initiating the process within a week of the meeting.

Post-Meeting Comments

Seven parties filed comments in response to the March 1 meeting: Alliance for Retail Energy Markets/Direct Access Customer Coalition, California Coalition of Utility Employees, Independent Energy Producers Association, California Large Energy Consumers Association, Commercial Energy, City of San Diego, and The Utility Reform Network. All informally submitted comments are attached to this report as Appendix C.

Themes of comments centered around data request template issues, transaction periods to include in the MPB, confidentiality issues, the transitional timeline, *de minimis* value for unsold RA, and lack of sufficient data to set benchmarks in some regions.

Working Group Participants

The "working group" references all active parties participating in Working Group One meetings, which includes PG&E and CalCCA representatives as well as meeting attendees. A list of participants is included in Appendix B.

Next Steps

Procedure for Items 1-7

PG&E and CalCCA will continue to convene via conference calls on a weekly basis and schedule extended in-person sessions to consider parties' comments and to further develop the proposal addressing issues 1-7. The co-chairs will meet with their respective constituents to ensure parties' viewpoints are documented and reflected in the resultant proposal.

Meetings Scheduled

A second meeting is scheduled for March 26, 2019 at 10:00 AM at the CPUC's San Francisco building. The meeting was noticed on March 19, 2019.

Additional Progress Reports/Final Report

The second progress report on items 1-7 is due April 22, 2019. The second report will address the second meeting, party comments, and further development of the straw proposal. The final report on items 1-7 is due May 31, 2019. The final report will detail the Brown Power, RPS, and RA benchmark and true-up proposal as developed by the co-chairs for review by the CPUC.

CPUC Decision

The CPUC is scheduled to issue a Proposed Decision on items 1-7 in September 2019 and anticipated voting on said Decision 30 days after issuance.

Procedural Schedule for Items 8-12

Meetings Scheduled

A third meeting is planned for May 2019 to address items 8-12, though a date has yet to be determined.

Additional Progress Reports/Final Report

The final report on items 8-12 is required to be filed and served by July 1, 2019.

CPUC Decision

The CPUC is scheduled to issue a Proposed Decision on items 8-12 in Fall 2019 and plans to vote on the Decision 30 days after issuance.

Appendices

- Appendix A: Initial Meeting Presentation
- Appendix B: Initial Meeting attendee list
- Appendix C: Informal Party Comments

PCIA Phase 2: Working Group One

Benchmark True-Up and Other Benchmarking Issues

Workshop #1: March 1, 2019

Agenda for March 1, 2019 Workshop

Discussion Topics

- Introduction & Background
- Timeline of Power Charge Indifference Adjustment (PCIA) - Related Proceedings/Activities
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PCIA Phase 2 – Working Group Roadmap

Three Concurrent Working Groups; Co-led by a Utility and CCA/DA Representative

2018 | 2019 | 2020

Phase 2: Policy Development

14

Create "Procurement Process Reference Guide"
- Joint Effort by All 3 IOUs

WG #1: Benchmark True-Up (PG&E/CalCCA)
- **Benchmarks and True-Up (Today's Focus)**
- Methodologies to Forecast Departing Load
- PCIA on Bundled Customer Bills
- Decisions Expected Q4 2019

WG #2: PCIA Prepayment (SDG&E/AReM/DACC)
- Calculation and Approval of PCIA Prepayments
- Decision Expected Q1 2020

WG #3: Portfolio Optimization (SCE/CalCCA/Commercial Energy)
- Disposition of Long Investor Owned Utilities' Portfolios
- Going-forward Portfolio Management Standards
- Decision Expected Q2 2020

Introduction and Background

Purpose of Today's Workshop

- Review Joint Straw Proposal developed to-date by Working Group One Co-Leads
  - Answer clarifying questions and receive feedback on Straw Proposal
  - Define outstanding topics for discussion
- Prepare interested parties to send comments one week from today's workshop
- Set the stage for topics that will be covered in future Working Group One workshops

Scoping Memo Guidance

Primary Focus of March 1st Workshop

- **Benchmark and True-Up Mechanism**

  (Scoping Memo 2.1.1 – 2.1.5):

  1. Which mechanism(s), procedural and/or methodological, should the Commission adopt to true up annually the Brown Power component, the Resource Adequacy (RA) adder and the Renewable Portfolio Standard (RPS) adder of the Market Price Benchmark?
  2. Are new data and/or transaction reporting requirements needed for the purposes of performing the true-up? If so, what are those data/reporting requirements and how should they be considered by the Commission?
  3. Should the true up process be addressed as part of the annual Energy Resource Recovery Account proceedings? If not, where should the true up process be addressed?
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  5. Should the Commission modify, or create new, transaction reporting for the purposes of deriving forecasts of next year's RA and RPS adders, including expansion and refinement of the Energy Division's annual RA Report, and if so, how?

Scoping Memo Guidance (Cont'd)

Primary Focus of March 1st Workshop

- **Benchmark and True-Up Mechanism (Cont'd)**

  (Scoping Memo 2.1.6 – 2.1.7):

  6. How should the Commission clarify/define forecasting amounts of unsold RA?
  7. D.18-10-019 specified that "a zero or *de minimis* price shall be assigned for [RA] capacity expected to remain unsold for purposes of calculating the MPB." Are further parameters needed to define a *de minimis* price, and if so, what are these parameters?

Kick-Off After March 1st Workshop

- **Other Items** (Scoping Memo 2.1.8 - 2.1.12)
  - Forecasting Departed Load
  - Vintage-Specific Billing Determinants
  - PCIA Presentation on Customer Bills

Working Group One Activities

Date	Co-Leads Coordination to-Date
1/29	Conference Call #1
2/12	Conference Call #2
2/13	Conference Call #3
2/15	Whiteboarding Session #1
2/20	Whiteboarding Session #2
2/26	Conference Call #4
2/27	Workshop Preparation #1

Date	Future Milestones
3/1	First All-Party Workshop (Focused on Benchmark and True-Up)
3/8	**Comments to All-Party Workshop Due**
3/20	First Progress Report (Focused on Benchmark and True-Up)
3/26	Second All-Party Workshop
4/22	Second Progress Report (True-Up and Other Issues)
May TBD	Third All-Party Workshop
5/31	Final Working Group Report on Benchmark and True-Up
7/1	Final Working Group Report on Other Issues
Q4	Separate Decisions on True-Up and Other Issues

Agenda for March 1, 2019 Workshop

Discussion Topics

- Introduction & Background
- Timeline of Power Charge Indifference Adjustment (PCIA) - Related Proceedings/Activities
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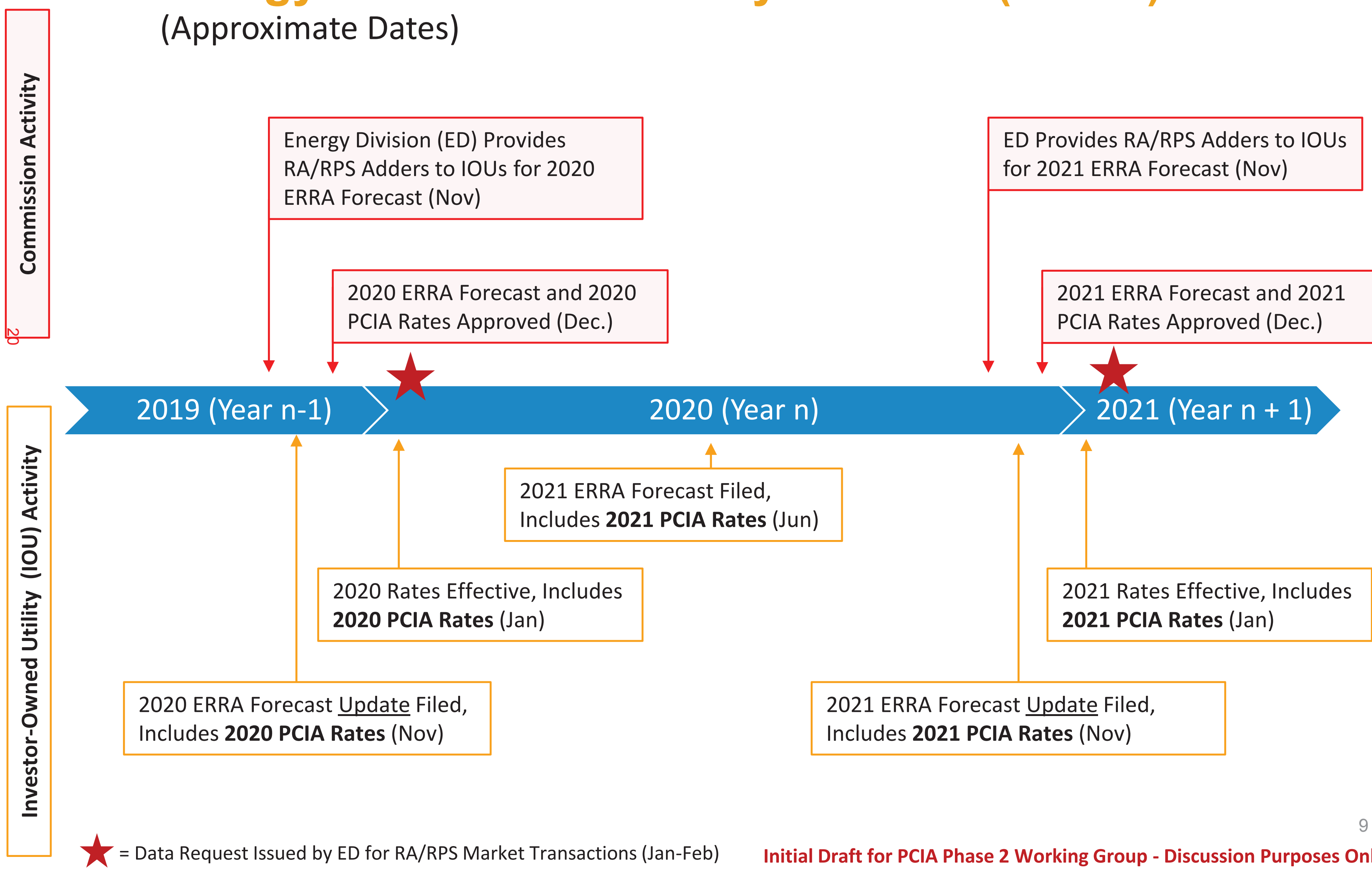
Today's ERRA Forecast Calendar

Energy Resource Recovery Account (ERRA)

(Approximate Dates)



Agenda for March 1, 2019 Workshop

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RA/RPS Adder Principles

Guiding Principles from PCIA Phase 1 Decision

- **Resource Adequacy (RA)**
  - "The RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n).[1]"
  - "A zero or *de minimis* price shall be assigned for capacity expected to remain unsold.[2]"

- **Renewable Portfolio Standard (RPS)**
  - "The RPS Adder shall be calculated using reported prices from purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year two years prior to the forecast year (year n-2) for delivery in the forecast year (year n).[3]"

[1] California Public Utilities Commission Decision (D.) 18-10-019, Ordering Paragraph 1
[2] Ibid
[3] Ibid

Summary of Straw Proposal by Co-Leads

Joint Proposal by Working Group Co-Leads

Proposals for Benchmark and True-Up Mechanism

- ED to issue data request in late September for submittal by all LSEs in October to cover additional transactions*
  - Data request template elements to be further discussed on slides 17-21
- By November 1st each year, ED will publish two separate RA/RPS Adders*
  1. “Forecast” RA/RPS Adder: To be used in setting the PCIA rates for the delivery year
  2. “Final” RA/RPS Adder: To be used in truing up the imputed RA/RPS PABA entries for products used by the IOU’s for compliance in the delivery year
- RA Adder: Includes market-based RA-only sales and purchases from IOU, CCA and ESP transactions
- RPS Adder: Is based on market-based PCC1 “index-plus” sales and purchases from IOU, CCA and ESP transactions
- ED to count the same (single) transaction between the same parties once for purposes of calculating the RA/RPS Adders

* Joint Proposal differs from D.18-10-019; Potential update to Decision language

Tomorrow's ERRA Forecast Calendar

Green = New Items

Joint Proposal by Working Group Co-Leads

Commission Activity

ED Issues Data Request to All LSEs (Sep)

ED Provides RA/RPS Adders to IOUs: (Nov)
- 2020 "Forecast RA/RPS Adder", **AND**
- 2019 "Final RA/RPS Adder"

2020 ERRA Forecast and 2020 PCIA Rates Approved (Dec.)

ED Issues Data Request to All LSEs (Sep)

ED Provides RA/RPS Adders to IOUs: (Nov)
- 2021 "Forecast RA/RPS Adder", **AND**
- 2020 "Final RA/RPS Adder"

2021 ERRA Forecast and 2021 PCIA Rates Approved (Dec.)

2019 (Year n-1) | 2020 (Year n) | 2021 (Year n + 1)

Investor-Owned Utility (IOU) Activity

2020 ERRA Forecast Update Filed, Includes **2020 PCIA Rates** (Nov)
- **2020 PCIA Rates Based on 2020 "Forecast RA/RPS Adder"**

2020 Rates Effective, Includes **2020 PCIA Rates** (Jan)

2021 ERRA Forecast Filed, Includes **2021 PCIA Rates** (Jun)

RA/RPS Adders True-Up (Nov)
- Products Used by IOU for compliance valued at **2020 "Final RA/RPS Adder"**

2021 ERRA Forecast Update Filed, Includes **2021 PCIA Rates** (Nov)
- **2021 PCIA Rates Based on "Forecast RA/RPS Adder" AND 2020 Under/Over Collection**

2021 Rates Effective, Includes **2021 PCIA Rates** (Jan)

★ = LSEs Submit Data to ED (Oct)

Initial Draft for PCIA Phase 2 Working Group - Discussion Purposes Only

“Forecast” Adders versus “Final” Adders

Joint Proposal by Working Group Co-Leads*

- By Nov 1st each year, Energy Division will publish two separate Adders

Nov 1, 2019
Energy Division Publishes
- Final RA/RPS Adders for 2019 (Year n-1)
- **Forecast RA/RPS Adders for 2020 (Year n)**

Nov 1, 2020
Energy Division Publishes
- **Final RA/RPS Adders for 2020 (Year n)**
- Forecast RA/RPS Adders for 2021 (Year n+1)

“Forecast Adders” for Year n

Transaction Input Data:
- Transactions Executed in Year n-2 (Q4), and Year n-1 (Q1-Q3) for Delivery Year n

Used by IOUs to:
- Forecast Market Value of PCIA Portfolio and Set PCIA Rate for Year n (2020)

“Final Adders” for Year n

Transaction Input Data[2]:
- Transactions Executed in Year n-1 (Q1-Q4) for Delivery Year n
- Augmented with Transactions Executed in Year n (Q1-Q3) for Delivery Year n

Used by IOUs to:
- True-Up Imputed PABA Entries for Products Used by IOUs for Compliance in Year n (2020)

(n-1) 2019

(Year n) 2020

* Joint Proposal differs from D.18-10-019; Potential update to Decision language

[2] For the “Final Adder”, transactions from Q4 of n-2 are dropped, and Q1-Q3 of year n are added

Benchmark and True-Up Mechanism Open Issues

Joint Proposal: Co-Lead Open Issues

- **<u>Open Issues</u>**
  - Use of backstop procurement (e.g. CAISO Capacity Procurement Mechanism (CPM)) in the RA Adder
  - Transitional issues (implementation timeline for 2019)
  - Implementation of the RA Adder to reflect the three types of RA capacity: system, local and flexible
  - Addressing unsold RA volumes

Agenda for March 1, 2019 Workshop

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Data Inputs to the RA/RPS Adders

Guiding Principles for Calculating the RA/RPS Adders

- **<u>Data Reporting Requirements</u>**
  - Based on the respective Commission-adopted methodologies, the data reporting requirements should include, at a minimum, the following:
    1. Contract ID
    2. Delivery Period(s)
    3. Purchased Product Parameters
    4. Counterparties
    5. Volume/Price
    6. Transaction Date(s)
  - Define standard and clear instructions and descriptions for the reporting requirements for LSEs
  - Establish a feasible <u>process for ED staff</u> to receive information from the IOUs, CCAs and ESPs and to publish the RA/RPS Adders

RA Data Request Template

Joint Proposal by Working Group One (Redline to Existing Data Request Template)

#	Data Field ~~Descriptions~~:	Data Field Description~~s~~:	
1	**Contract ID Between Parties**	Insert the ~~LSE~~ parties' unique contract identifier	Contract ID
2	**Month**	Select the delivery month for which the price quoted is applicable; Please insert an additional row for each month regardless of whether capacity price or capacity MW amount changes between months	Delivery Month/Year
3	**Year**	Select the year of delivery	
4	**Resource Scheduling ID**	CAISO Resource ID	Product Parameters
5	**Resource Name**	Name of resource	
6	**[New] Unspecified Resource**	If the resource is unspecified (capacity transacted without a specific resource identified); Indicate the CAISO Zone, if applicable	
7	**Buyer**	Contract buyer	Parties to the Transaction
8	**Seller**	Contract seller	
9	**~~Generic~~ System Capacity Under Contract (MW)**	The amount of ~~generic~~ System MW(s) under contract for the associated month and year of the contract	Volume(s)
10	**[New] Local Capacity Under Contract (MW)**	The amount of Local MW(s) under contract for the associated month and year of the contract	
11	**Flexible Capacity Under Contract (MW)**	The amount of Flexible MW(s) under contract for the associated month and year of the contract	
12	**Price ($/kW-Month)**	List the price in $/kW-Month format for each month and year of the contract even if the price is same for all months of the year; For example, if a contract covers a 3-year period, you will input 36 lines for the contract	Price(s)
13	**Contract ~~Signed~~ Execution Date**	List the date the contract ~~was originally signed~~ is executed; If there has been an extension signed you do not need to list that date - MM/DD/YYYY	Execution Date
14	**Type of Generation**	Select whether the resource is New or Existing generation; A repower will be considered New generation for this application	
15	**Combined Heat and Power (CHP) Contract**	Select Yes if the contract is a CHP contract; Select No if the contract is not a CHP contract	

RPS Data Request Template (1 of 3)

Joint Proposal by Working Group One (Redline to Existing Data Request Template)

Field Name	Field Type	Unit	Allowable Values	Choice Definition	Not Applicable for	Submittal Instructions
[New] Contract ID	Text	N/A	N/A	N/A	N/A	Insert the parties' unique contract identifier.
Seller Name	Text	N/A	N/A	N/A	UOG - leave blank	Name of the seller ~~counterparty (~~to the LSE~~)~~ on the contract. Leave blank for UOG. The name of the special purpose entity can be included in this field.
[New] Buyer Name	Text	N/A	N/A	N/A	N/A	Name of buyer on the contract. The name of the special purpose entity can be included in this field.
Project Name	Text	N/A	N/A	N/A	N/A	Input the name of the project as presented in the contract or other official project documents.
CAISO Resource ID	Text	N/A	N/A	N/A	Imports	Enter CAISO Resource ID. Enter "N/A" for projects outside the CAISO balancing area, or projects that do not have a resource ID because they are too small under the CAISO rules and their PPA.
Contract Execution Date	Date	YYYY-MM-DD	Date after 1900-01-01	N/A	N/A	The date on which the original RPS contract/PPA (including both sales and purchases) were executed by the parties. If contract is converting from QF to RPS, put the execution date of the RPS contract. If contract was amended and restated in the year n-~~2~~1, use the n-~~2~~1 date and include previous contract execution date(s) in Project Notes.

RPS Data Request Template (2 of 3)

Joint Proposal by Working Group One (Redline to Existing Data Request Template)

Field Name	Field Type	Unit	Allowable Values	Choice Definition	Not Applicable for	Submittal Instructions
[New] Month	Date	YYYY-MM-DD	Date after 1900-01-01	N/A	N/A	Select the delivery month.
[New] Year	Date	YYYY-MM-DD	Date after 1900-01-01	N/A	N/A	Select the year of delivery.
[New] Volume(s)	Integer (>=0)	MWh	N/A	N/A	N/A	List the volumes for each month and year of the contract even if the volumes are the same for all months. If the volumes span multiple months in a calendar year, parties shall assume an equal distribution for each delivery month of that year or years.
Contract Length (Years)	Integer (>=0)	Years	Whole number >=0	N/A	UOG - leave blank	For projects with executed contract, include Term per contract. For projects in the Overall Contract Status "Under Negotiation" or "In Development", include expected Term. For contracts with the term "Evergreen" (i.e. those that automatically renew until cancelled) include "999". Leave blank for UOG.
Expected PCC Classification	Choice	N/A	Category 0, Category 1, Category 2, Category 3	Category 0: gradfathered projects executed before June 1, 2010. Category 1 -3: refer to D.11-12-052	N/A	Forecast which PCC classification is expected to apply to generation of the project (pursuant to D.11-12-052). For projects with multiple expected PCC classifications, input the classification associated with the majority of energy.

RPS Data Request Template (3 of 3)

Joint Proposal by Working Group One (Redline to Existing Data Request Template)

Field Name	Field Type	Unit	Allowable Values	Choice Definition	Not Applicable for	Submittal Instructions
Contract Price (pre- TOD adjusted)	Decimal (>=0)	$/MWh	Decimal number >=0	N/A	UOG, QF - leave blank	For PPA: Levelized pre TOD-Adjusted Final Contract Price ($/MWh) over the term of the contract. If project has more than one price (e.g., wet and dry), put the higher price in the cell and explain in Project Notes. If the contract price has been amended, this column should have the most recent price, and previous price(s) should be included in Project Notes. For REC + Energy, provide the REC-only premium price. Leave blank for UOGs and historic QFs.
Contract Price (TOD adjusted)	Decimal (>=0)	$/MWh	Decimal number >=0	N/A	UOG, QF - leave blank	For PPA: Levelized TOD-Adjusted Final Contract Price ($/MWh) over the term of the contract. If project has more than one price (e.g., wet and dry), put the higher price in the cell and explain in Project Notes. If the contract price has been amended, this column should have the most recent price, and previous price(s) should be included in Project Notes. For REC + Energy, provide the REC-only premium price. Leave blank for UOGs and historic QFs.

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Portfolio Allocation Balancing Account (PABA)

Procedural Mechanism to Accomplish True-Up

- Decision 18-10-019, Ordering Paragraph 7 required a Tier 2 Advice Letter to establish a Portfolio Allocation Balancing Account (PABA) with a subaccount for each vintaged portfolio.

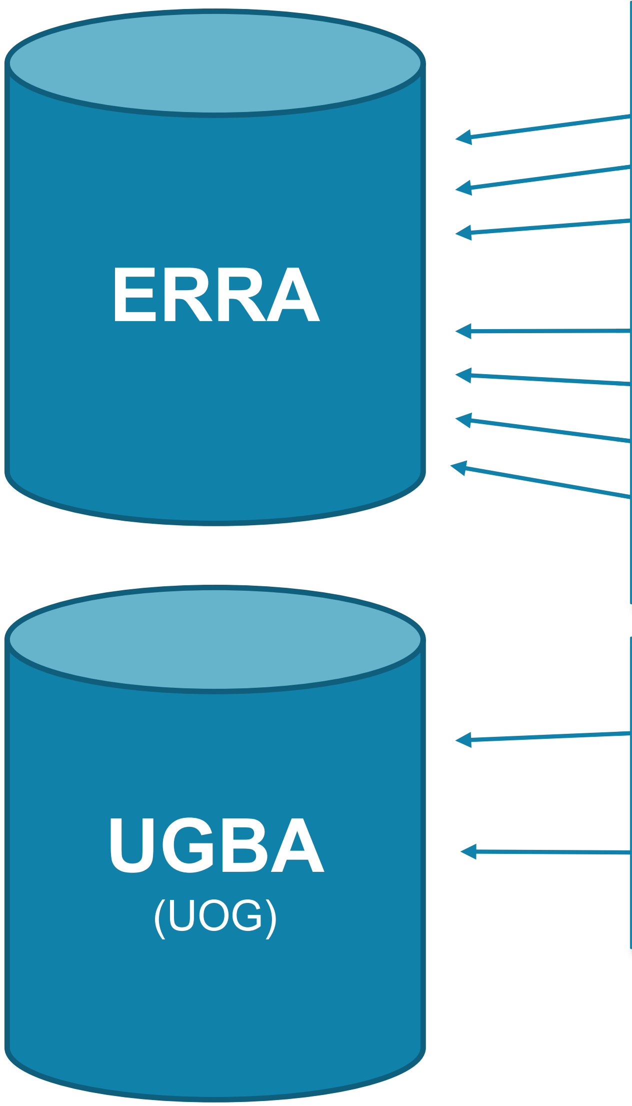
- The PABA is to include:
  - Billed revenues;
  - Generation resource costs;
  - Net CAISO market revenues associated with energy and ancillary services;
  - Revenues associated with the RPS Adder and;
  - Revenues associated with the RA capacity

Portfolio Allocation Balancing Account Advice Letters

- SCE PABA Advice Letter: https://www1.sce.com/NR/sc3/tm2/pdf/3914-E.pdf
- SDG&E PABA Advice Letter: http://regarchive.sdge.com/tm2/pdf/3318-E.pdf
- PG&E PABA Advice Letter: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5440-E.pdf

ERRA/UGBA Present State (Debits + Credits)

Each Item Booked as a ***Single*** Entry for the Month



Debits
- 3rd Party Power Purchase Contracts
- Fuel and GHG Costs (UOG and PPA)
- Short-term and Market Purchases

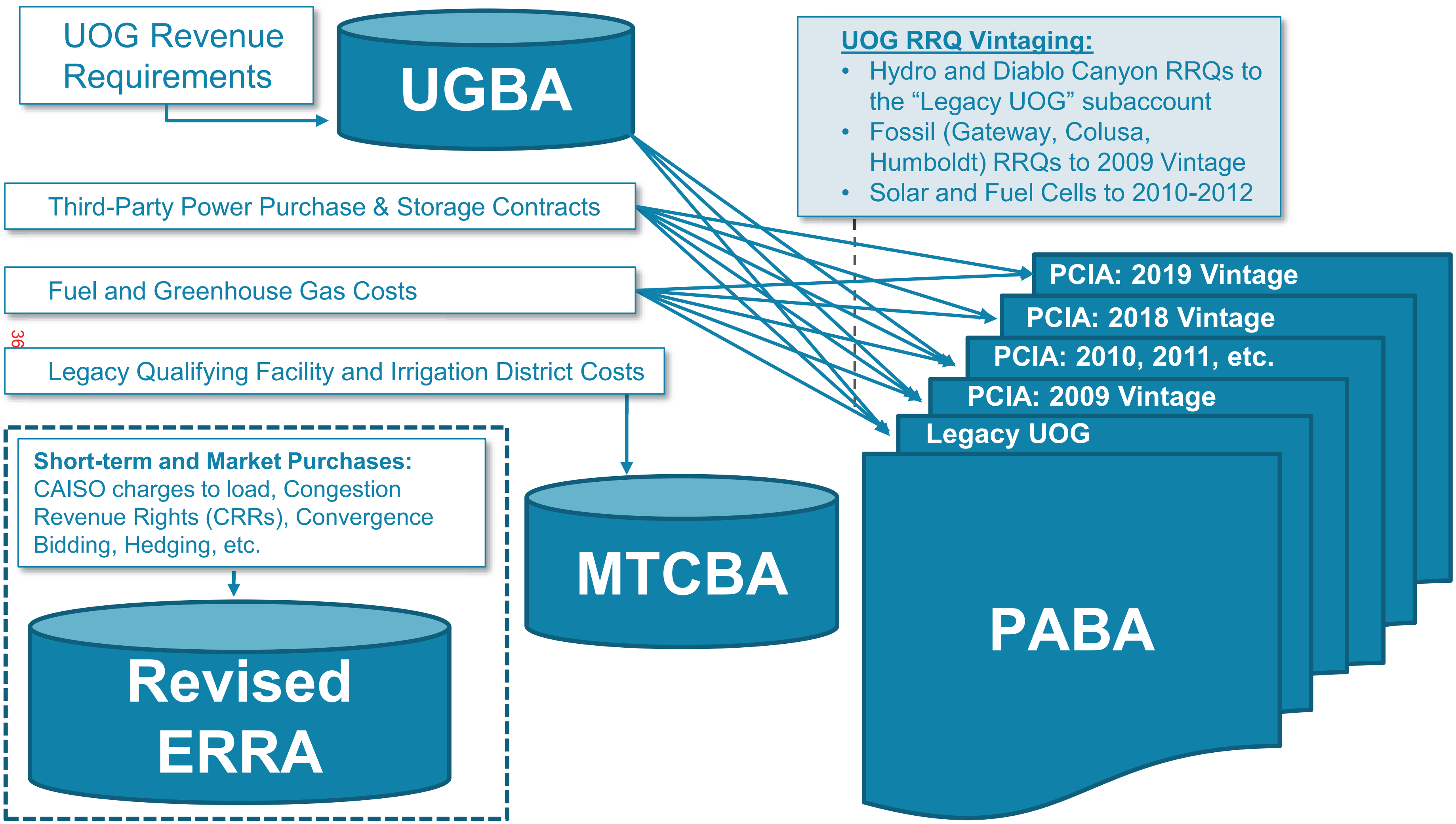
Credits
- CAISO Energy and A/S Revenues
- RPS and RA Sales Revenue
- CCA/DA Billed Revenue (PCIA Rate)
- Bundled Billed Revenue (ERRA Component of Generation Rate)

Debits
- UOG Revenue Requirements

Credits
- Bundled Billed Revenue (Bundled Residual Amount)

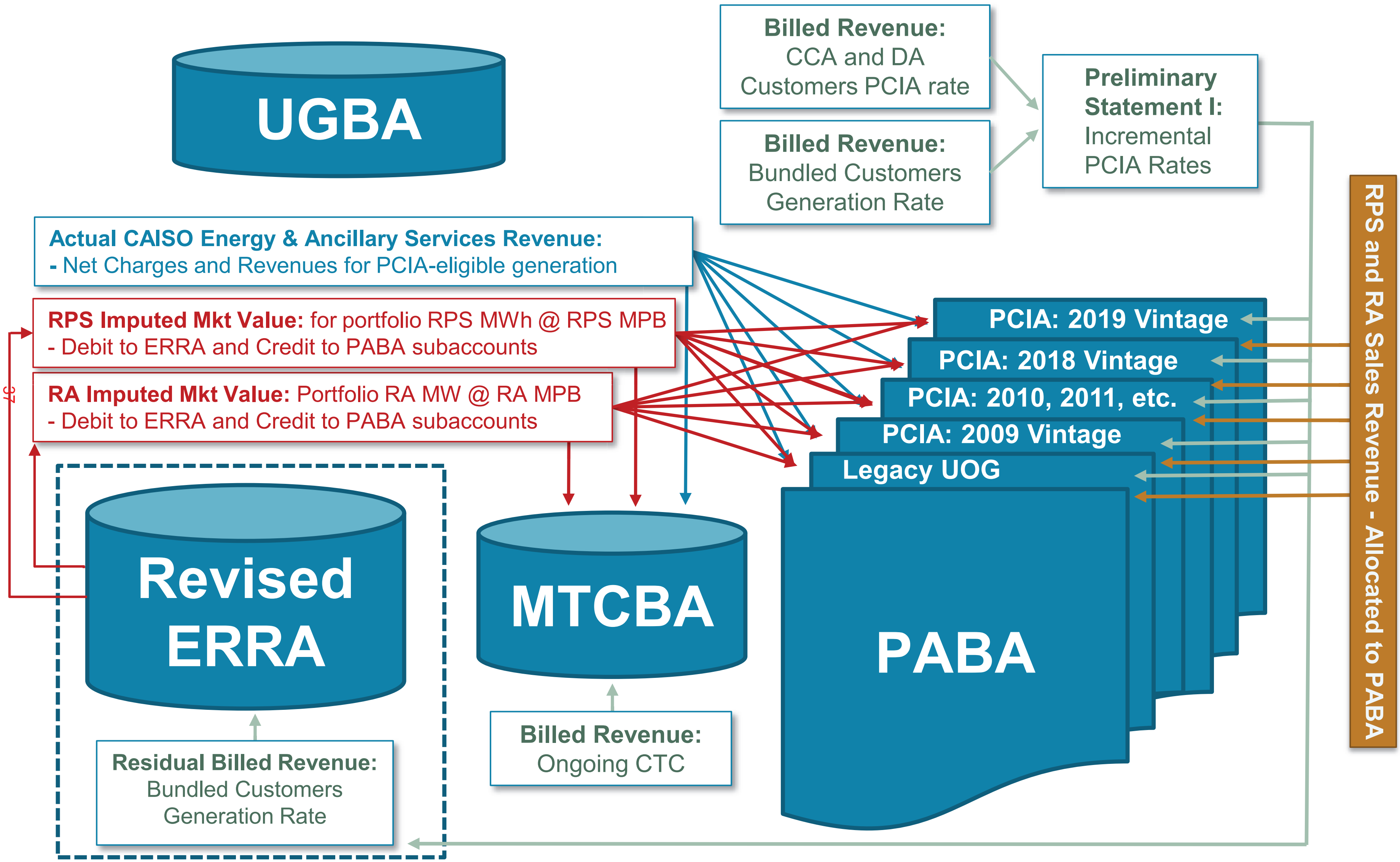
PABA Future State (DEBITS)

UOG RRQ will continue to be booked as UGBA, then transferred to each PABA subaccount



PCIA-eligible contract and fuel costs will be recorded directly to each PABA subaccount

PABA Future State (CREDITS)

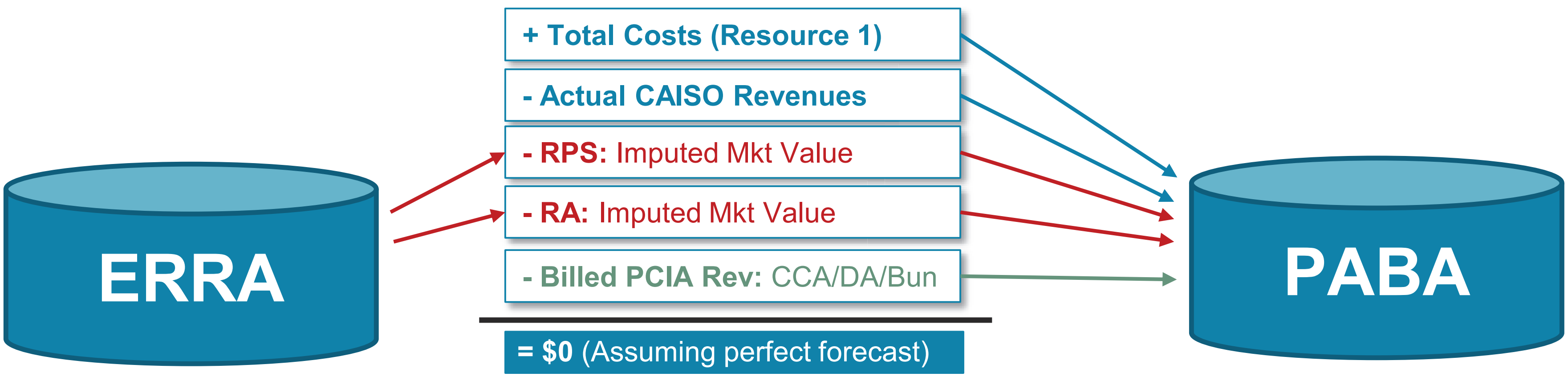


Beginning in 2019, ERRA, not UGBA, will receive residual generation revenues

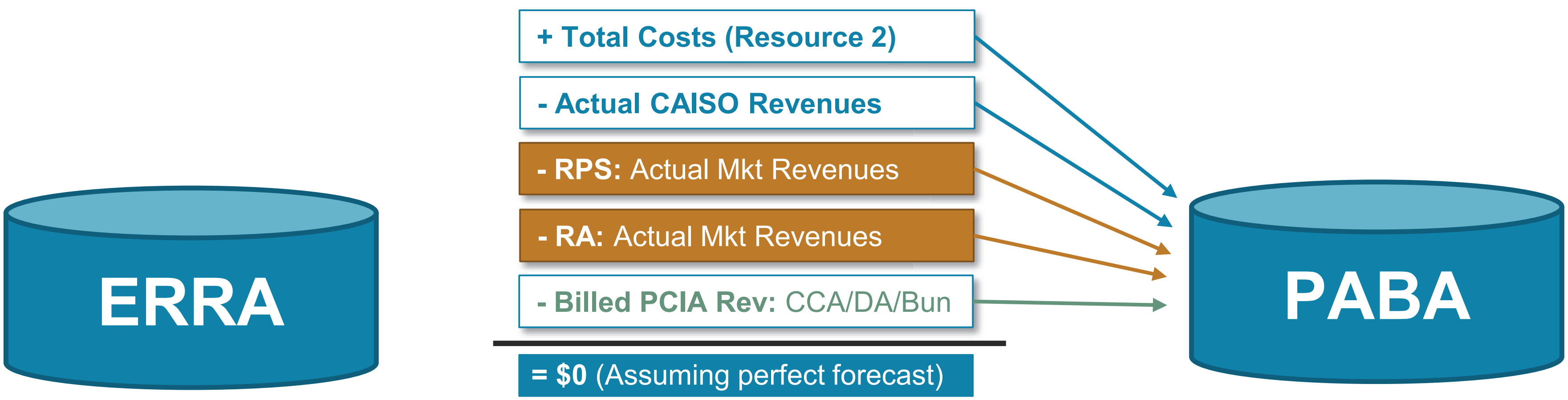
High-Level Summary: ERRA and PABA

Imagine a PCIA portfolio consisting of 2 solar resources in a single vintage

- Resource 1 is used by bundled customers for compliance



- Resource 2 is sold to another market participant



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Scoping Memo Guidance (Cont'd)

Primary Focus of March 1st Workshop

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- **Other Items** (Scoping Memo 2.1.8 - 2.1.12)
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  – PCIA presentation on customer bills

Summary of Straw Proposal by Co-Leads

Joint Proposal by Working Group Co-Leads

Proposals for Benchmark and True-Up Mechanism

- ED to issue data request in late September for submittal by all LSEs in October to cover additional transactions*
  - Updates to the data request template required to facilitate RA/RPS Adder calculations
- By November 1st each year, ED will publish <u>two</u> separate RA/RPS Adders*
  1. “Forecast” RA/RPS Adder: To be used in setting the PCIA rates for the delivery year
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- RA Adder: Includes market-based RA-only sales and purchases from IOU, CCA and ESP transactions
- RPS Adder: Is based on market-based PCC1 “index-plus” sales and purchases from IOU, CCA and ESP transactions
- ED to count the same (single) transaction between the same parties once for purposes of calculating the RA/RPS Adders

* Joint Proposal differs from D.18-10-019; Potential update to Decision language

Q&A and Discussion

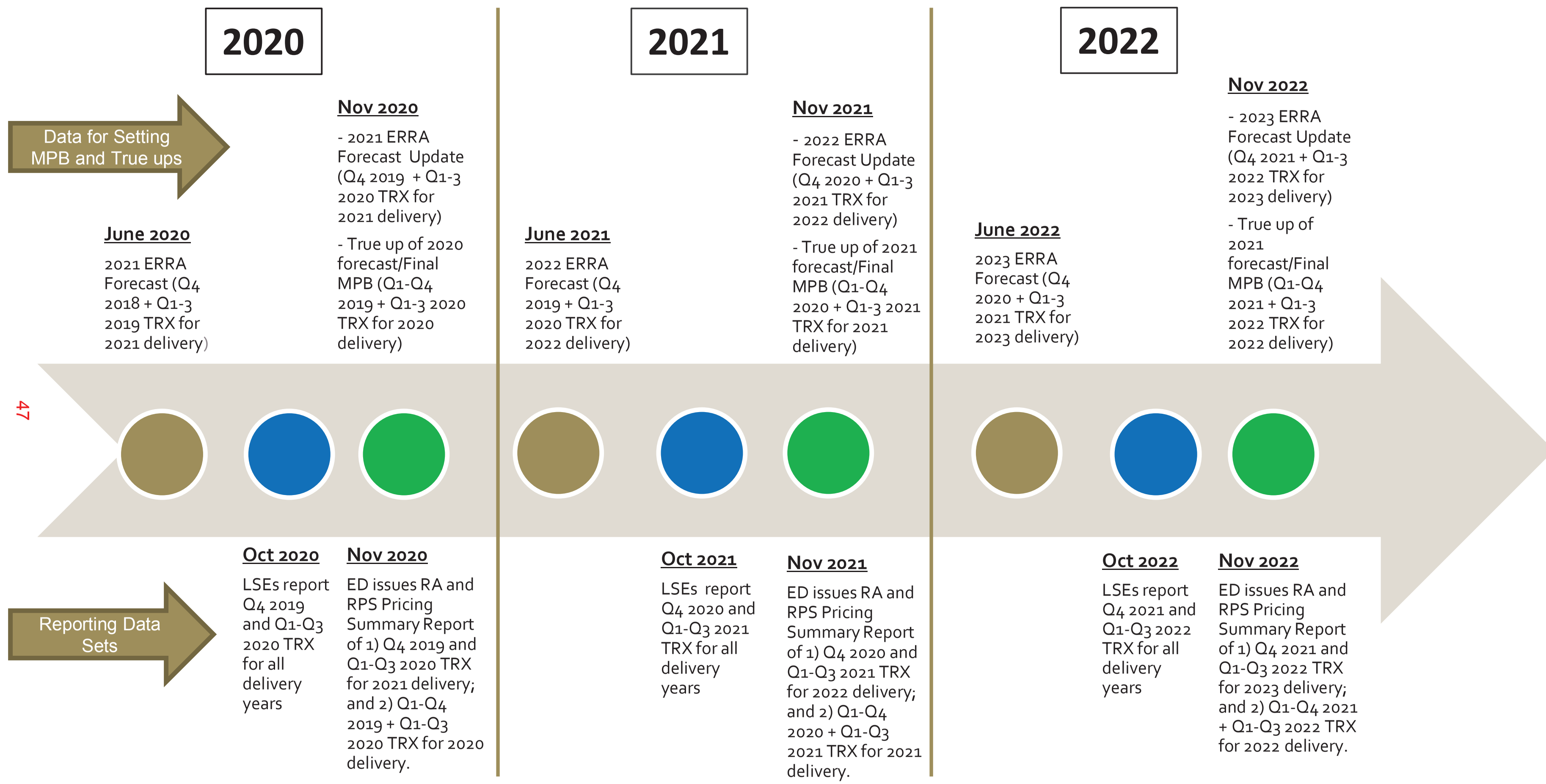
Comments on Workshop #1 Due: Friday, March 8, 2019

Appendix

Transition Issues

- Implementation and timing considerations if the Decision is delayed
- Use of alternatives in establishing the RA/RPS Adders if the Decision is delayed

Detailed Timeline of Proceedings/Activities (ERRA)



"n" = transaction delivery year
"n-1" = 1 year prior to delivery year
"n-2" = 2 years prior to delivery year

June Activities
October Activities
November Activities

In Person Workshop Participants

Name	Organization	Email
Andrew Klingler	PG&E	askb@pge.com
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Ian Quirk	PG&E	imq1@pge.com
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Russell Archer	SCE	russell.archer@sce.com
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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP #1 STRAW PROPOSAL (WORKSHOP #1)

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March 8, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

INFORMAL COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE DIRECT ACCESS CUSTOMER COALITION ON PCIA WORKING GROUP #1 STRAW PROPOSAL (WORKSHOP #1)

The Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC) appreciate the effort that was clearly made by PG&E and CalCCA in developing the Straw Proposal presented at the March 1 workshop. AReM/DACC also welcome the opportunity to respond to the Straw Proposal and look forward to working through the remaining issues in the upcoming workshops. We are optimistic that the parties will be able to come to consensus on many of the thorny issues that have been so well laid out.

The comments here address four issues that AReM/DACC believe can be improved upon and/or added to the Straw Proposal and offer responses to the four open issues identified at the Workshop (slide 15).

I. REPORTING TEMPLATES

The schedule suggested in the Straw Proposal is aggressive: the load serving entities (LSEs) must populate the resource adequacy (RA) and renewable portfolio Standard (RPS) templates and the energy division (ED) analyze resulting data from well over 20 LSE in a matter of weeks. In this light, AReM/DACC believe that the templates include ONLY the data needed by the ED to calculate the RA and RPS adders (for both the forecast MBP and for true-up). To that end, AReM/DACC recommends that just RA and RPS purchases are reported, and not sales.

Reporting purchases should capture all RA transactions and the vast majority of RPS transactions. If sales are included in the reporting and in the benchmark and true-up calculations, additional work will be required of the ED staff to line up the reported sales and purchases of RA and renewable energy certificate ("RECs") among the CPUC jurisdictional LSEs so to ensure that no transaction is double-counted. This is unnecessary and burdensome. The only sales that should possibly be reported would be RECs to non-CPUC jurisdictional LSE that would not otherwise be reported as a purchase.

In addition, AReM/DACC recommend the following specific changes or clarifications to the template:

1. Remove the "month" requirement from the RPS template. Unlike RA, it is unnecessary for the RPS adder calculation and simply adds complexity to the reporting process as well as additional work for the ED.

2. Additional clarity is needed under the "Volume" entry in the RPS template. Would the LSE enter the anticipated REC deliveries, or perhaps some other value, such as the minimum or maximum deliveries specified in the PPA being reported? The template released in January 2019 appropriately asked for volume bounds to capture different potential contract structures.

II. RA/RPS ADDERS

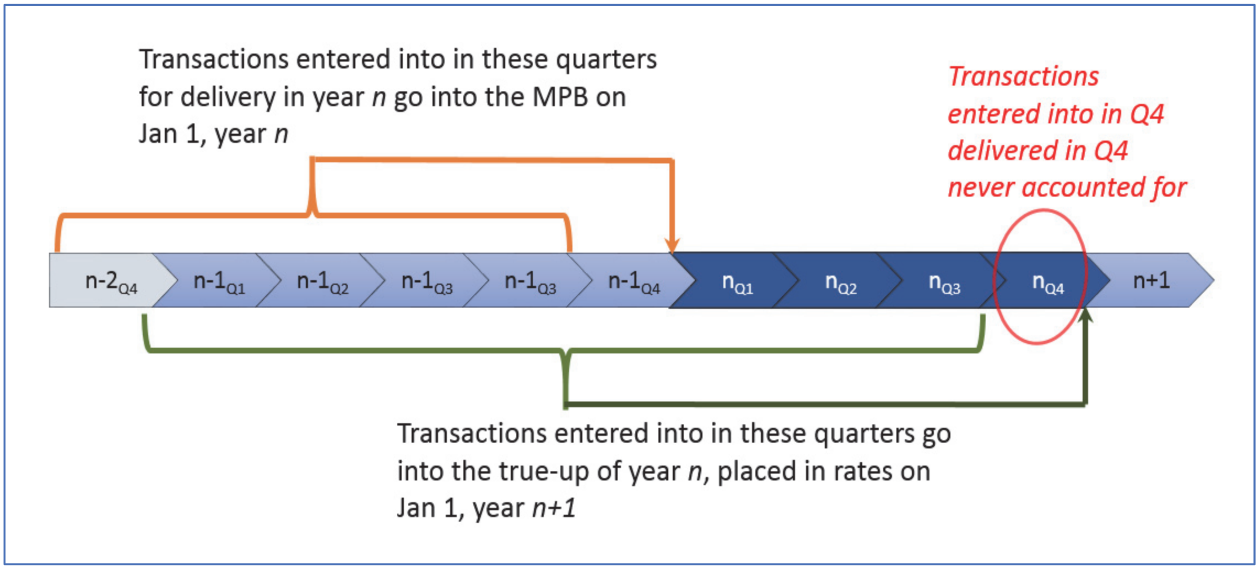
AReM/DACC believes that additional effort is needed to explore if, and how, to include bundled contracts (i.e., a single price for a contract delivering energy, RA and RPS) when estimating RA and RPS adders. This could theoretically be done by breaking out the RA and RPS value of fixed price contracts using proxy delivery shapes for resources and known net qualifying capacities for intermittent resources. However, AReM/DACC acknowledge that this is no trivial exercise and that there is a real risk of getting these numbers wrong. For example, a calculation suggesting that a REC has "negative value" is non-sensical. At plain face value, this would mean that LSE would have to pay to give away the RECs associated with renewable generation, in spite of the fact that they could be banked for future use. If the proposed approach to imputing RA or

REC values from bundled contracts proves to be unacceptable to stakeholders, then AReM/DACC is comfortable using the RA-only and index-plus-REC transactions for the benchmarks and true-up at this time but feels that this is an issue that should be resolved for future benchmarking exercises.

III. TRUEING UP FOURTH QUARTER RPS TRANSACTIONS

The Straw Proposal suggests that the RA and RPS Benchmarks (for year n) be set using

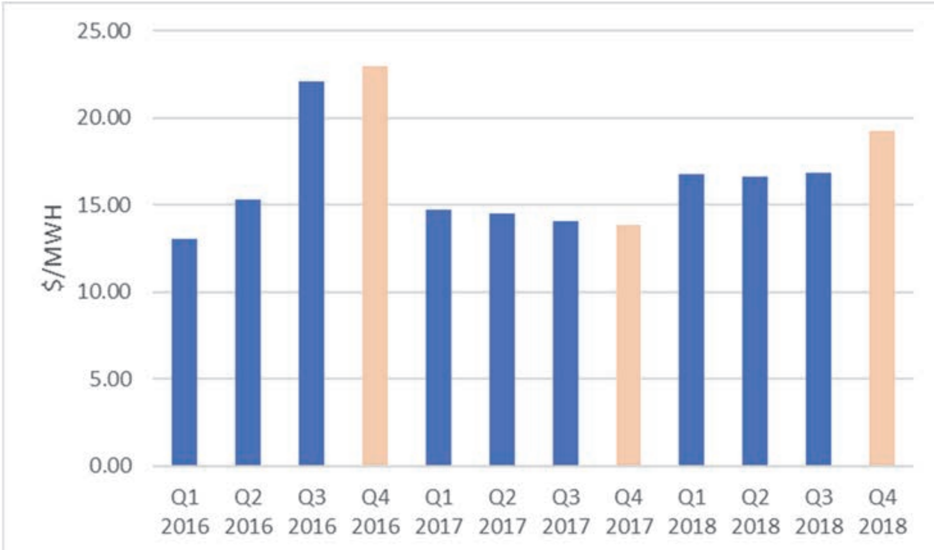
Figure 1. Market Price Benchmark (MPB) Forecast and True-up Schedule



LSE data reported from Q4 (year n-2) through Q3 (year n-1) for delivery in year n. For the RA and RPS benchmark true-ups for year n, the Straw Proposal suggests using actual transactions from year n-1 (Q1-Q4) and from year n (Q1-Q3) delivered in year n. However, the value of transactions in the 4th quarter of with deliveries in the 4th quarter of year n are never trued-up.

If the prices and volumes of transactions in the 4th quarter of the year are modest or at least consistent with the prior quarters, then missing this data is not consequential. However, since RPS compliance is on a calendar year basis, it may be the case that the prices in that quarter immediately before the end of the compliance period can be higher than the rest of the year. Some simple (not weighted) average data from *Platts* suggests that may be the case.

Figure 2. Simple Average Quarterly PCC1 (Bucket 1) REC Prices



IV. CONFIDENTIALITY

AReM/DACC note that D.18-10-019 at pages 78-79 recognizes that data submitted for the true-up process will include market sensitive information and that the provisions of General Order-66-D will apply, such as the need for the responding LSE to include an affidavit as to the nature of the data provided and why confidentiality is required. AReM/DACC propose in addition that access to the information be restricted solely to the individuals within Energy Division tasked with the responsibility to calculate the RA and RPS adders (for both the forecast MBP and for true-up). Once the adders have been finalized and adopted for inclusion within rates, the data should either be destroyed or returned to the responding LSE.

V. COMMENTS ON OPEN ISSUES (SLIDE 15)

Slide 15 of the Joint Proposal presentation lists 4 open issues. Below are AReM/DACC's thoughts on those issues.

1. Use of the backstop procurement (e.g., CAISO Capacity Procurement Mechanism) in the RA adder

AReM/DACC currently have no comments on this item, except as noted in item 4., below.

2. Transition Issues (implementation timeline for 2019)

AReM and DACC are optimistic that the issues being addressed in this working group can be resolved in time for implementation in 2020. While this may require a month or two delay in the ERRA/PABA implementation, that delay is well worthwhile. If major intractable issues arise, then AReM/DACC would recommend the process used for 2019 for the RA and RPS adders and true-up only the brown power component.

AReM/DACC would like clarification for how the RPS and RA cost data submitted in January and February of 2019 will be used during this transition.

3. Implementation of the RA Adder to reflect the three types of RA capacity: system, local, and flexible

AReM and DACC believe that that Decision 18-10-019 clearly states that all three RA types must be included. As the types, prices and volumes of RA are included in the reporting template, different values should be calculated for each RA type, including the different values for each Local RA area. These numbers should then be compared against the cost of RA being held by each IOU to calculate numbers that can be included in the PCIA. Under this approach, care must be taken to prevent double counting for resources which qualify as multiple different types, with the value based on a determination of what the resources would have been used for in the absence of load departure.

4. Addressing unsold RA volumes

RA that is sold or used for IOU compliance should be valued at [zero], with the following exception: if any LSE cannot purchase RA and must file for a waiver and the IOU has unsold volumes of that type of RA, then the unsold RA should be valued at the CPM soft offer cap in the benchmark.

VI. CONCLUSION

AReM/DACC thank the Working Group co-chairs for their hard work and look forward to working through these and undoubtedly other issues.

Respectfully submitted,

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March 8, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COMMENTS OF THE COALITION OF CALIFORNIA UTILITY EMPLOYEES ON PCIA PHASE 2 – WORKING GROUP ONE WORKSHOP #1

March 8, 2019

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026

COMMENTS OF THE COALITION OF CALIFORNIA UTILITY EMPLOYEES ON PCIA PHASE 2 – WORKING GROUP ONE WORKSHOP #1

I. INTRODUCTION

The Coalition of California Utility Employees (CUE) appreciates the opportunity to provide comments on the March 1, 2019 PCIA Phase 2 Working Group One: Benchmark True-Up and Other Benchmarking Issues Workshop #1. CUE seeks clarification or has suggestions on several issues. First, CUE requests clarification that the proposed "final" RA and RPS adders would only be used for true-up of resources used by bundled customers for compliance, and that otherwise, actual market revenues would be used in the true-up. Second, CUE seeks clarification on the reasoning for adopting the proposed RPS adder. Third, CUE believes more specificity is needed in the calculation of the proposed RPS and RA adders. Finally, CUE offers a suggestion for the data template.

II. CLARIFICATION ON THE USE OF FINAL ADDERS FOR TRUE-UP

Working Group One proposes that the RA Adder include "market-based RA-only sales and purchases from IOU and ESP transactions."[1] The RPS adder "is based on market-based PCC1 'index-plus' sales and purchases from IOU, CCA, and ESP transactions."[2] A 'forecast'

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[1] PCIA Phase 2: Work Group One, Benchmark True-Up and Other Benchmarking Issues, Workshop #1, March 1, 2019, ("WG Presentation"), p. 12.
[2] Id.

version of each adder would be used in setting the PCIA rates for the delivery year. A 'final' version of each adder would be used in the true-up process.[3] It appears that the difference between the forecast and final adders is the data used for the calculation. The forecast adder uses historical data prior to the forecast year, while the final adder uses actual data from the year to be trued up.[4]

In D.18-10-019, the Commission delayed implementation of RPS and RA true-ups because "…the recorded 'actuals' do not reflect the untransacted capacity used for bundled customers' compliance or the untransacted RECs either used for compliance or banked for future use."[5] CUE requests that Working Group One confirm that the final adders would only be used to address the Commission's concern about untransacted capacity and RECs, and that actual IOU market transactions would be used in all other cases.[6]

III. CLARIFICATION ON RPS ADDER

Working Group One proposes an RPS adder "based on market based PCC1 'index-plus sales and purchases from IOU, CCA, and ESP transactions."[7] An alternative to this approach might be to use bundled sales including PPAs. CUE seeks to understand why this alternative approach would not be viable or is less preferable.

IV. ADDER SPECIFICITY

While the definitions of the adders proposed by Working Group One give some

[3] Id.
[4] Id., p. 14.
[5] D.18-10-019, p. 141.
[6] WG Presentation, p. 27 may address this, but clarification would be helpful. If it is not the case that the final adders would be limited to resources used for compliance, then cost shifts would inevitably occur between bundled and departing customers because the adders are based on CCA and ESP transactions as well as IOU transactions.
[7] Id., p. 12.

indication of the calculation methodology for the adders, the exact calculations need to be laid out in detail. Such detail should include clarification on the following issues:

1. How will the adders be calculated geographically? Will adders be specific to each IOU, each CAISO zone, or just one in each category for all IOUs (forecast and final RA, forecast and final RPS), or perhaps some other geographical division? If the value of RA or RPS differs amongst the IOUs, but a single adder is used, cost shifting would occur. Since the true-up would occur at an average value rather than the true value, in some areas departing customers would benefit at the expense of bundled customers, and in other areas bundled customers would benefit at the expense of departing customers. This use of a system-wide adder when IOU values differ would violate the principle of customer indifference.

2. Are all contracts that include optionality excluded from the calculation? If not, how will the transaction price reflect the optionality including any premium payments? If contracts with optionality are excluded, it would be useful for the data template or instructions for the data template to indicate this.

3. How will the weighting of different contracts work concerning execution date and delivery dates? It is CUE's understanding that Working Group One proposes long-term contracts would be included in the calculation of the RA and RPS adders, but only for the first year of delivery of the contract. For instance, if a contract has been signed two years before the delivery year, it would not be included in the adder for the delivery year. Please clarify.

V. SUGGESTIONS FOR THE DATA TEMPLATE

The data template presented by Working Group One would be used to collect data for the calculation of the RA and RPS adders as well as for other purposes. Because of these other purposes, it includes data that will not be used for the calculation of the RA and RPS adders.

This combination of data for different purposes in the template resulted in some confusion at the March 1, 2019 workshop concerning how the adders would be calculated. CUE understands that it is more efficient for some of the parties to only have one data template to fill out, rather than have a separate data template for purposes of calculating the adders. CUE tends to believe having a separate data template for the adders would add clarity to the adder calculation methodology. However, CUE suggests that if only one data template is used, the template should clearly indicate which data would be used in the adders calculation. For example, the template should indicate for the "Expected PCC Classification" row which of the allowable values (Categories 0 to 3) would permit a contract to be included in an adders calculation.[8]

Dated: March 8, 2019

Respectfully submitted,

/s/

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[8] See also discussion above about contracts that include optionality.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	**Rulemaking 17-06-026** **(Filed June 29, 2017)**

INFORMAL COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON WORKING GROUP ONE WORKSHOP #1 HELD MARCH 1, 2019

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March 8, 2019

BN 35847120v1

CLECA[1] appreciates the efforts of the co-leads and this opportunity to offer informal comments on workshop #1. As a threshold matter, we recommend inclusion of all parties' informal comments distributed to the service list today as an appendix to the Working Group Progress Report to be served on March 20, 2019 pursuant to the February 1, 2019 Phase 2 Scoping Memo and Ruling of Assigned Commissioner.

CLECA offers the following informal comments to Working Group One Workshop #1. These informal comments make four points:

- Use of backstop procurement "(e.g., CAISO Capacity Procurement Mechanism (CPM)) in the RA Adder" should not be a "Co-Lead Open Issue" pursuant the directive in D. 18-10-019;
- Additional time for the Energy Division may be needed for the implementation timeline in 2019;
- Unsold RA Volumes' de minimis value should be between 5-10% of the contract price (instead of a zero value); and
- Confidentiality concerns over protections for procurement cost data should be addressed.

1. Do Not Use the CPM in the RA Adder Benchmark

Slide 15 of the March 1 workshop presentation lists four items identified as "Co-Lead Open Issues" in the Joint Proposal. The first item is "Use of backstop procurement (e.g. CAISO Capacity Procurement Mechanism (CPM)) in the RA Adder." CLECA's counsel understands that

[1] CLECA is an organization of large industrial electric customers of Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE); the member companies are in the steel, cement, industrial gas, mining, pipeline, cold storage, and beverage industries and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite generation. CLECA has been active in Commission proceedings since the early-to-mid 1980s and strives for even-handed treatment of all customers.

there was little to no actual discussion of this item at the workshop. CLECA strongly disagrees that use of the CPM price in the RA Adder should be considered an "open item" given the clear language in D. 18-10-019. D. 18-10-019 states,

> we adopt new benchmarks for the RPS Adder and the RA Adder in order to improve the initial accuracy of the PCIA that will be in effect each year. We also adopt an annual true-up requirement to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented."[2]

Specifically regarding the RA Adder, the Commission directed use of TURN's RA Adder:

> we adopt TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n). A zero or de minimis price shall be assigned for capacity expected to remain unsold.[3]

TURN's RA Adder did not include use of the CPM. Moreover, in response to CalCCA's proposal to use the CPM to benchmark capacity, CLECA's testimony in R. 17-06-026 explained why the CPM price is not appropriate for use in the RA Adder or for benchmarking capacity costs:

> Reliability Must Run and CPM contracts are used for backstop when resources that are not contracted for RA are determined through power flow studies to be needed for reliability. Market prices for capacity have been dampened by the existence of excess capacity procured for policy reasons other than capacity value, such as RPS procurement.
>
> CalCCA proposes to use the soft offer cap for the CAISO's backstop CPM that is used in cases of RA resource deficiency (most recently in local capacity areas or subareas), exceptional dispatch (e.g. for a transmission emergency), or for significant events (unexpected conditions like the shut-down of the San Onofre Nuclear Generating Stations (SONGS)). It can be used for as little as 30 days or as long as a year. This is the going forward fixed cost of a 550 MW combined cycle plant with duct firing plus a 20% adder. 24 It is currently $75.68/kW-year. The CPM is only used in the case of a deficiency, which is for the CAISO occasioned by a reliability concern. Thus, by its very nature, if a resource is procured through the CPM, it is not surplus capacity. Furthermore, the soft offer cap has become something of a floor, since recent CPM procurement has occurred at values very close to the soft cap. For these reasons, I do

[2] D. 18-10-019, at 62.
[3] D. 18-10-019, at 73.

> not support its use as proposed by CalCCA as a value for surplus capacity, nor do I support CalCCA's determination of surplus capacity.[4]

The working group process should not be subverted into re-litigation of issues already decided by the Commission. D. 18-10-019 is clear that the RA Adder is to be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions"; this does not include use of a CAISO administratively-determined price, e.g., the CPM.

2. Consider Giving Energy Division Additional Time This Year to Process Data

The schedule on slides 13-14 and slide 31 states that Energy Division will issue the data request "in late September" and the Load Serving Entities are to provide the data "in October" and the ED is to produce the benchmarks or adders on November 1. This year is the first year for staff to implement the new benchmarking process for the RPS Adder and the RA Adder, and they will be getting data from multiple LSEs. Additional time this first year may be warranted. CLECA suggests for 2019 that the data request to the LSEs be issued in early September, and be due back by the first week of October; this would give staff most of the month of October to review the data and crunch the numbers.

3. Set the Unsold RA Volumes' De Minimis Value at between 5-10% of the Contract Price

The Commission directed that, "A zero or de minimis price shall be assigned for capacity expected to remain unsold."[5] CLECA does not believe it would be good policy for a zero value to be assigned to resources whose procurement was previously authorized by the Commission and approved as meeting the "just and reasonable" standard. CLECA supports use of a de

[4] Ex. CLECA-1 in R. 17-06-026, Testimony of Dr. Barbara R. Barkovich, at 12.
[5] D. 18-10-019, at 73, 121.

minimis value of between 5-10% of the contract price for contracts that are unsold. We suggest this range as a practical solution, and do not believe significant time should be used to determine “further parameters.” Using a 5-10% contract price valuation should not significantly impact the RA Adder, and it recognizes some level of value remaining in the available capacity.

4. Address Confidentiality Concerns for Procurement Cost Data

CLECA understands that some energy service providers are concerned about the confidentiality protections for their market sensitive procurement and contract data. We believe that this is a valid concern, and would support a request for destruction of the LSEs’ confidential procurement data after the Energy Division staff has crunched the numbers and produced the benchmarks. If the benchmark calculation needs to be re-visited later, it should be understood that the confidential LSE data could be re-sent to Energy Division.

CLECA looks forward to continued engagement in this working group.

Respectfully submitted,

Buchalter, A Professional Corporation

By:

Nora Sheriff

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Consumers Association

March 8, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CITY OF SAN DIEGO INFORMAL COMMENTS ON DRAFT PROPOSAL REGARDING BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

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The City of
SAN DIEGO
Sustainability

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026

CITY OF SAN DIEGO INFORMAL COMMENTS ON DRAFT PROPOSAL REGARDING BENCHMARK TRUE-UP AND OTHER BENCHMARKING ISSUES

Pursuant to the schedule established at the workshop for Working Group 1, The City of San Diego (City) respectfully submits these informal comments on the initial draft proposal titled "Benchmark True-Up and Other Benchmarking Issues" (Proposal) that was presented at the workshop on March 1, 2019 in Working Group 1 in Phase 2 of Rulemaking (R.) 17-06-026 (the PCIA proceeding).

The City appreciates all of the hard work that went into the development of the Proposal and the opportunity to provide comments to enhance the next iteration of the Proposal.

The City has selected Community Choice Aggregation (CCA) as the preferred pathway to reach its 100 percent renewable electricity goal in the City's landmark Climate Action Plan. Recently, City Council approved a resolution to begin the process of establishing a Joint Powers Authority (JPA) to form a CCA. The CCA is expected to serve customers starting in 2021.

Given the state of the of the City's CCA efforts, the City's perspective is different than that of CCAs that are fully operational; the City's concerns with the Proposal are more closely related to those of a new CCA that is in the early phases of bringing on new customers. In addition, the City is different than some CCAs, in that it, is likely that the vast majority of the City's Resource Adequacy (RA) obligations will consist of Local RA, meaning that the Commission's recent

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decision regarding the multi-year Local RA obligation (Decision (D.) 19-02-022) could have a significant impact on the City's CCA efforts.

Expanded Calendar

The City appreciates the Energy Resource Recovery Account (ERRA) Forecast Calendar in the Proposal. The City found this to be very helpful in understanding how the Proposal fits into the ERRA calendar. The City believes that the calendar should be expanded to show how the Proposal fits into the other schedules that impact the establishment of the Power Charge Indifference Adjustment (PCIA) and the True-Up: (1) the calendar for procurement of and reporting on RA, and (2) the Energy Division's RA reports (especially given the requirements from the recent RA decision regarding multi-year Local RA obligations). By providing this expanded calendar, it will be clear if there are any unintended calendar conflicts resulting from the Proposal.[1]

New CCA Issues

Since the City plans to be part of a CCA that starts serving customers in January 2021, it wants to make sure that its intentions are accurately reflected in the Benchmarks for both RA and RPS adders as well as in the true-ups of those adders. In particular, the City would like the next iteration of the Proposal to clarify that the IOU, which are currently serving the loads of a future CCA, reflects the expectations regarding the loads that should depart when a new CCA is formed. This reflection should be documented in the reporting phase. This is especially important when considering the new multi-year Local RA obligation and will minimize all ratepayer costs.

[1] The City understands that the precise timing for implementation of the multi-year Local RA program is still uncertain. However, even a *pro forma* estimate of timing could prove useful in coordinating between the workshop processes in the PCIA and RA proceedings.

Interaction Between Benchmarks, Benchmark True-Up, and Multi-Year Local RA Program

As noted above, the City plans to join a CCA that expects to start serving load in January 2021. This overlaps with the Local RA obligation established for SDG&E as part of the Multi-Year Local RA program from D.19-02-022.[2] If the Commission implements its Multi-Year Local RA program this year, then SDG&E will procure 100% of its Local RA obligation for 2020 and 2021 (and 50% of its Local RA obligation for 2022) based on its load share in 2020, which is before the City's CCA is in existence and before a CCA Implementation Plan will be filed with the Commission. Clearly, if the City's CCA ultimately starts serving customers in 2021, then SDG&E would have significantly over-procured Local RA for 2021 (and possibly 2022) based on its activities in 2019. The City is concerned that this almost inevitable over-procurement would result in an artificial bias in either the PCIA or the true-up to the PCIA. However, this may not be an issue if, as noted in the Presentation, "The RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n)".[3]

The City recommends that the next iteration of the Proposal clarify how the Multi-Year Local RA obligations and procurement by SDG&E and other IOUs will affect both the Benchmark and the True-Ups.

Establishing Benchmarks in Thinly Traded Markets

The RA benchmark will be based on reported purchase and sales prices from IOU, CCA, and ESP transactions made during (year n-1) for delivery in (year n).[4] Both the Benchmark and the True-Up depend on those transactions. There are significant numbers of transactions on behalf of

[2] SDG&E will have a three-year obligation based on its load share in the first of the three years ("As the Commission is unable to anticipate when new LSEs will form or how load will migrate among LSEs beyond the one-year timeframe, at this point, **all LSEs will be allocated local requirements for each of the three forward years based on their load share in the first year** resulting from the adopted California Energy Commission (CEC) load forecasting process. Requirements for Years 2 and 3 will be updated during the following year's year-ahead allocation process." D.19-02-022, p. 28 (emphasis added)).
[3] D.18-10-019, Ordering Paragraph 1.
[4] D.18-10-019, Ordering Paragraph 1.

IOUs, CCAs, and ESPs in the PG&E and SCE service territories. However, SDG&E may be different: SDG&E has only one CCA (Solana Energy Authority) and a significant amount of SDG&E's load is met either by Utility Owned Generation (UOG) resources or long-term Power Purchase Agreements (PPAs). In addition, much of SDG&E's RA obligation is met through Local RA resources, (e.g., the recently-approved five-year PPA between SDG&E and Otay Mesa Energy Center).[5] Because of these conditions, it is possible that SDG&E might have little or no need for making short-term RA purchases.

The City suggests that the next iteration of the Proposal address how a thinly-traded market might affect the reasonableness of the RA Benchmark and/or the True-Up.

Conclusion

The City appreciates all the hard work that went into the development of the Proposal and looks forward to participation in the development and finalization of the Benchmark True-Up and other issues related to the PCIA.

Dated: March 8, 2019.

Respectfully submitted,

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[5] Resolution E-4981, Option A.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting a Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMERCIAL ENERGY OF CALIFORNIA INFORMAL COMMENTS ON WORKING GROUP ONE FOR PHASE II

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Dated: March 8, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting a Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMERCIAL ENERGY OF CALIFORNIA
INFORMAL COMMENTS ON WORKING GROUP ONE
FOR PHASE II

Pursuant to agreed-upon procedures discussed at the Working Group 1 Workshop held on March 1, 2019, Commercial Energy of California ("Commercial Energy") hereby provides its informal comments on the work product of Working Group #1.

Commercial Energy does not have any comments at this time on the proposed schedule and mechanism for developing RPS and RA adders and incorporating them into the utilities ERRA filings. Commercial Energy reserves the right to make additional substantive comments on these issues in the future.

1. Confidentiality of Load Serving Entity Data Responses

Commercial Energy notes that the Working Group co-chairs' "strawman proposal" includes a more detailed data request template for both RA and RPS. Pursuant to the decision in Phase I of the PCIA, with the caveat that LSE reporting requirements are still subject to pending rehearing applications and potentially appeals, all LSEs including Community Choice Aggregators (CCAs), Energy Service Provides (ESPs) and Investor Owned Utilities (IOUs) are required to provide detailed contract data regarding power purchase agreements that have RPS or

RA attributes. Commercial Energy notes that such contract information is highly confidential and extremely commercially sensitive to all LSEs, but particularly to ESPs. In addition, given that the Commission does not have direct jurisdiction over the rates that ESPs charge their customers, it is important that if such information is provided to the Commission and its staff that it is provided under procedures designed to carefully preserve the LSEs' confidential trade secrets and competitive procurement pricing information.

Accordingly, Commercial Energy makes the following proposals for inclusion in the final product of Working Group #1 related to the new data reporting requirements.

1. All Data Responses provided by an LSE pursuant to the proposed procedure for developing RA and RPS adders shall be provided directly to Energy Division and, pursuant to the provisions of General Order 66-D, shall be accompanied by a declaration of an officer of the entity providing the contract data which sets forth the basis for confidential treatment as required by the General Order.

2. The Data Response shall be provided only to a designated Energy Division recipient, and to no other parties. The Energy Division recipient shall share the confidential data responses only with the Energy Division personnel directly responsible for calculating and publishing the proposed RA and RPS adders.

3. After the adders are calculated by the Energy Division, provided to the IOUs for inclusion in subsequent ERRA filing, and the Commission issues a decision in the ERRA proceeding adopting the new RA and RPS adders, then the confidential LSE data held by Energy Div. is to be destroyed or returned to the respective LSEs.

Commercial Energy is prepared to discuss its proposal in additional detail in the next Working Group #1 Workshop.

Respectfully submitted March 8, 2019, at San Francisco, California.

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMENTS ON PCIA PHASE 2: WORKING GROUP ONE (BENCHMARK TRUE-UP) WORKSHOP # 1

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	Rulemaking 17-06-026 (Filed June 29, 2017)

COMMENTS ON PCIA PHASE 2: WORKING GROUP ONE (BENCHMARK TRUE-UP) WORKSHOP #1

By Ruling dated February 1, 2019, the Assigned Commissioner set forth the category, issues, and other matters related to Phase 2 of the Power Charge Indifference Adjustment (PCIA) proceeding (Rulemaking 17-06-026). Phase 2 will rely primarily on a working group (WG) process to develop PCIA-related proposals for consideration by the Commission. Working Group One will address proposals related to PCIA Benchmark True-up and Other Benchmarking Issues.[1]

Working Group One convened an initial workshop (Workshop #1) on March 1, 2019. The Independent Energy Producers Association respectfully submits these comments on certain of the issues raised during Workshop #1.

Workshop #1 considered a "Proposal for Establishing the Resource Adequacy (RA) and Renewable Portfolio Standard (RPS) Adders" and "Proposed Changes to Data Reporting Requirements" submitted by representatives of load-serving entities and retail sellers, *i.e.,* the utilities, community choice aggregators (CCAs), and electric service providers (ESPs). Data inputs proposed to be included in the PCIA benchmarking mechanism include data that are

[1] Phase 2 Scoping Memo and Ruling of Assigned Commissioner, p. 3.

market-sensitive and confidential to market participants, including sellers of RA capacity and RPS-eligible energy and Renewable Energy Credits. For example, data inputs include the amount of flexible RA capacity under contract by seller, contract execution dates between buyer and seller, contract prices ($/kW-Month), contract volumes sold, and generation resource costs. Moreover, proposed changes to the data reporting requirements appear to expand the collection of market-sensitive information to include volumes of various market products (*e.g.,* RA, RPS) bought and sold for each month and year of a contract.

The Commission must ensure that the Commission's rules governing market participants' access to market-sensitive and confidential data apply in the context of PCIA benchmarking. PCIA benchmarking should not become the backdoor for market participants to access market-sensitive and confidential information. For example, inappropriate access to confidential data could occur if a load-serving entity or retail seller subject to PCIA benchmarking sought an audit of the core data inputs to verify the accuracy of PCIA Benchmarking outcomes. Accordingly, in the context of PCIA Phase 2, the Commission should clarify and affirm that data collected for purposes of PCIA benchmarking will be subject to the Commission's rules on data confidentiality.

Respectfully submitted March 8, 2019, at San Francisco, California.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #1 WORKSHOP

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March 8, 2019

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PHASE 2 WORKING GROUP #1 WORKSHOP

TURN appreciates the effort parties made to develop the PCIA Phase 2: Working Group 1 "Straw Proposal" regarding Benchmarking True-up and Other Benchmarking Issues reviewed at the March 1 workshop in R.17-06-026. TURN has two concerns with the proposal that should be addressed. Due to the very short timeline for comments, TURN identifies basic concerns in the hope of focusing parties on these issues in upcoming workshops.

I. CONCERNS WITH THE PROPOSED RPS ADDER

The Straw Proposal would compute an "RPS Adder" based strictly on "index-plus" transactions in which a purchaser buys RPS-eligible energy at a price equal to a market price index plus an "adder" to reflect the extra value of renewable energy. TURN believes this paradigm is dated and must be discarded. It is not clear that any such RPS Adder will be a credible representation of market prices for renewable energy over time given the decline in pricing for bundled long-term renewable energy project PPAs in recent years. The approach proposed by the Working Group does not accommodate the potential for renewable energy purchased via bundled PPAs to be priced at or below the brown power index in any future year.

Table 1 below illustrates the potential for the RPS Adder approach to mis-estimate the value of RPS-eligible resources.

TABLE 1
Possible Renewable Benchmark Using Only "Index-Plus" Transaction Data
($/MWh)

Scenario:	1	2	3	4	5	Notes:
Brown Power	20	30	40	50	60	1/
RPS Adder	20	20	20	20	20	2/
Renewable Benchmark	40	50	60	70	80	3/

Notes:

1/ Possible indexed brown power values.

2/ Possible fixed value of RPS Adder based on Straw Proposal.

3/ Sum of Brown Power and RPS Adder.

Under the Straw Proposal, a fixed RPS Adder would be developed from transaction data based only on "index-plus" transactions. Table 1 shows a hypothetical adder of $20/MWh for all five scenarios. However, the price of indexed energy or brown power may vary considerably within a year and between years for a variety of reasons, such as changes in gas prices, localized gas deliverability constraints or changing supply and demand.[1] Table 1 shows that the presumed price of RPS-eligible resources under the Straw Proposal would vary based on the price of brown power. Although this relationship may be accurate for index-based contracts, there is no evidence to suggest that the cost of new fixed-price PPAs will be correlated with short-term changes in brown power price indexes.

A very high percentage of the legacy renewable PPAs in the IOU portfolios eligible for inclusion in the PCIA involve long-term fixed prices for bundled energy and Renewable Energy Credits (RECs). Both these legacy PPAs and new long-term fixed-price PPAs for new renewable generation executed by other LSEs in the coming years will be priced

[1] TURN uses the terms "indexed power" and "brown power" interchangeably in this document. However, given the growing amounts of renewable energy in Western power markets, this equivalency may not hold in the future. This is another reason to question the basic "RPS Adder" approach.

based on the long run costs of building, owning and operating new resources. Given the decline in the costs of new renewable generation, the prices for new PPAs may end up being lower than the brown power price over many years of the contract.

The use of floating indexes plus fixed adders proposed by the working group is representative of the market for short-term purchases from existing resources where prices are tied to short-term opportunity costs. Under that approach, the REC premium would be based on short-term supply and demand balances and could rise substantially in the final year of RPS compliance periods when some LSEs scramble to lock in supplies necessary to meet multi-year obligations. This approach does not contemplate the REC adder becoming negative and will never result in a renewable energy price benchmark that drops below short-term brown power prices. This outcome would be unchanged even if brown power prices rise substantially due to short-term trends relating to gas prices or supply/demand balance for renewable resources. The potentially significant disconnect between short-term index-based purchases from existing projects and long-term fixed price contracts for new projects could undermine the ability of the proposed benchmark to approximate the actual prices paid for contracts with new renewable facilities.

Starting in 2021, all LSEs will be required to procure at least 65 percent of RPS compliance through contracts with durations of at least ten years.[2] Most of these long-term contracts are likely to involve fixed prices for bundled energy and RECs from newly developed generation. As a result, a significant portion of renewable energy contracting will not be priced based on the indexing approach proposed for use in the MPB. If current pricing trends continue, many of these new contracts will be priced at or below forecasted long-term brown power market prices.

[2] Cal. Pub. Util. Code §399.13(b).

Given these realities, the exclusion of all long-term fixed price PPAs from the MPB would skew the calculation of above-market costs by limiting the “market” to short-term transactions that will represent a declining share of new renewable energy procurement. TURN urges the Working Group, and the Commission, to avoid any final proposal that fails to consider these PPAs from the benchmark methodology.

A more direct approach to estimating the price of renewable energy would be to gather data regarding the sale and purchase of bundled PCC1 RPS-eligible energy including both fixed price and index priced contracts. Such data could be gathered in the same fashion as the Straw Proposal proposes to gather RA purchase and sales data. The value of RA could be extracted from such sales by applying estimated RA prices and resources’ Net Qualifying Capacity for RA purposes.[3] Such computations would yield better estimates of the price of RPS-eligible energy.[4] Another alternative would be to cap the value of the RPS Adder used to compute the total value of RPS-eligible energy to reflect its potential to be negative.

TURN recognizes that there is an additional complication relating to the proposed use of contracts signed in the prior year (n-2) providing delivery of renewable power in the current year (n).[5] Because there may be a delay of more than 2 years between the execution of a long-term fixed-price PPA and the initial commercial operation of the facility, TURN proposes that fixed-price contracts for new facilities be counted in the benchmark starting with the first year of initial commercial operation and continue for three years.

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[3] For wind and solar resources, the computation of NQCs relies in part on Effective Load Carrying Capability (ELCC) calculations.

[4] If there is a need to estimate a specific RPS Adder, it should be computed based on this bundled PCC1 price, minus RA value, minus the cost of indexed or brown power. The resulting adder could be either positive or negative. If such values are negative, it is unlikely they would show up in market transactions, that is, sellers of RPS-eligible energy will not sell such energy on an “index-plus-negative-adder” basis.

[5] D.18-10-019, Ordering Paragraph 1(c).

II. TREATMENT OF CONTRACT EXTENSIONS

The “RA Data Request Template” shown on Slide 18 raised additional issues regarding prices of current contracts that are extended. As a general principle, the prices of contracts that are voluntarily extended by both parties should be assumed to be current as of the date of such an extension. TURN suggests that the direction that the dates of contract extensions need not be listed be stricken and that contracts that are extended voluntarily by both parties should be considered as “fresh” market data for the year of the extension.

However, TURN further observes that some utility contracts – such as renegotiated Qualifying Facility contracts – might not be “market transactions”; rather, the “prices” contained in such contracts might instead reflect in part the prices that were agreed upon many years ago. Additional care must be exercised to exclude such contracts that are not strictly market transactions but are instead negotiated with an eye toward changing the terms of a contract.

TURN appreciates the chance to file these comments.

Respectfully submitted,

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Dated: March 8, 2019